10 ASSET INTEGRITY

Hibiscus has conducted a Red Flag Review on asset integrity for the assets included in the transaction. The report is included here (Section 10) for reference.

10.1 Executive Summary

A Red Flag review was conducted on the facility integrity of the package of assets to be divested by Repsol for the exploration and production of oil and gas offshore Peninsular and Sabah Malaysia.

The first production from PM3 CAA was achieved by Lundin in 1997 from BKA LWS wellhead platform to an FPSO. Talisman acquired Lundin Malaysia and Vietnam assets ahead of the PM3 South main development coming on stream in 2003. South Angsi began production in 2005 and along with Kuning and Naga Kecil production ceased in 2019 and is in the process of abandonment. Angsi Southern Channel (ASCU) is operated by PCSB with first production in 2014. Kinabalu was developed by Shell with first production in 1997. Talisman acquired the Kinabalu field in 2012 follow relinquishment by Shell at the end of the initial PSC period. Repsol acquired Talisman in 2015.

A team of expert personnel was established to identify whether the risks of acquiring the assets was acceptable and that asset integrity had been maintained to an adequate standard such that the risks of owning such assets were acceptable.

The team had access to a virtual data room where information was provided regarding integrity status and the inspection and maintenance of the assets. In addition, a dedicated breakout discussion was held with the vendor's technical team. Review of the data has led to the conclusion that the assets are in relatively good condition for their age and operating environment. While there are some known integrity issues with infield pipelines and jackets, which may require remediation before end of the PSC, there were no significant immediate integrity concerns identified.

This report estimates the incremental costs which are likely to be incurred to address potential integrity issues to end of PSC for both PM3 CAA and Kinabalu and the further 10 years for PM3 CAA.

10.1.1 Fields and Assets

There are 9 producing fields under the PM3 CAA & Block 46 (Cai Nuoc), Kinabalu and PM305/PM314 PSCs plus 3 non-producing fields undergoing abandonment. Repsol Oil and Gas Malaysia Limited (RLM) is the operator of 8 producing hydrocarbon fields and 3 non-producing fields. The operated fields are grouped as follows:

- PM3 CAA & Block Cai Nuoc (Bunga Kekwa, East Bunga Kekwa/Cai Nuoc, Bunga Raya, Bunga Seroja, Bunga Tulip, Bunga Orkid, Bunga Pakma)
- Kinabalu
- PM305/PM314 South Angsi (South Angsi, Kuning and Naga Kecil)

PCSB operates the one remaining field, Angsi Southern Channel (ASCU) in block PM305 under the GPSC.

The oldest producing field is Bunga Kekwa which began production in 1997 while the newest is Bunga Pakma which started producing in 2018. The assets comprise 17 offshore structures, 2 Floating Storage and Offloading vessels and 650km of interconnecting subsea pipelines.

South Angsi began production in 2005 and along with Kuning and Naga Kecil production ceased in 2019. The FSO has been decommissioned and plans are advanced for well abandonment, and removal of the South Angsi fixed facilities.

The assessment conducted are for the Repsol operated assets. Insufficient data was released by Repsol (and PCSB) for the PCSB-operated asset to make an informed assessment.

10.1.2 PM3 CAA & Block 46 Cai Nuoc Summary

PM3 CAA is a collection of gas and oil producing fields in the Commercial Agreement Area, offshore Peninsular Malaysia between Malaysia and Vietnam (Figure 10.1). PM3 is centred round two fully manned hubs, Bunga Raya Complex in the south and Bunga Orkid Complex in the north. Produced gas is high in CO_2 and mercury, and the installed facilities process the fluids to remove the mercury and reduce CO_2 to 8% for gas sales and reduce mercury in exported liquids.

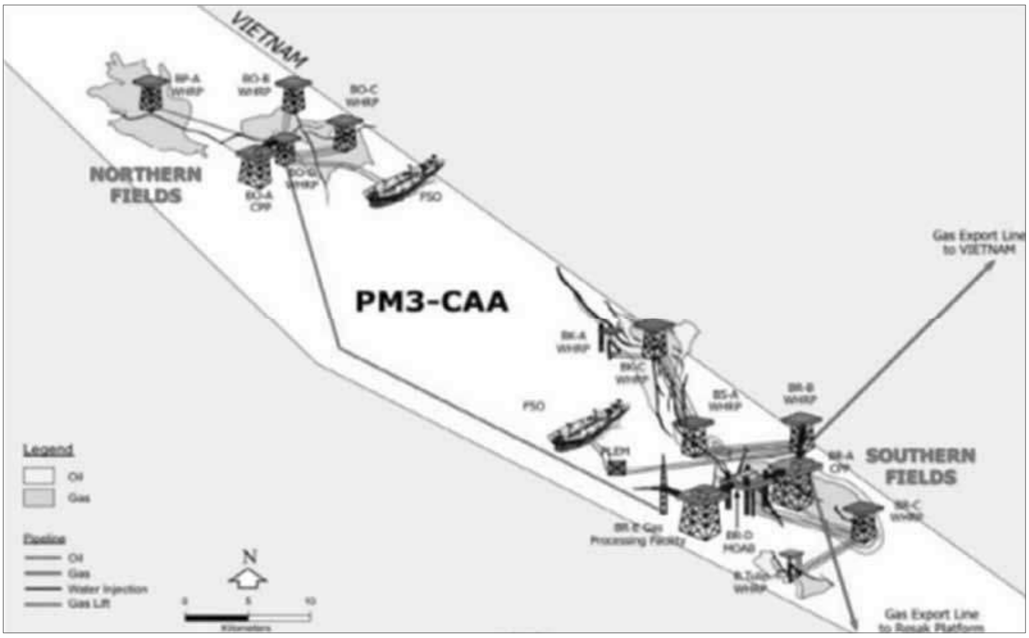

Figure 10.1: PM3 CAA Location Map

PM3 has total liquid production capacity of 53,000bpd and gas sales of 320 MMscfd (at 8% CO_2). Current production of 214 MMscfd sales gas (8% CO_2) and 18,000bpd (including condensate) is below the design capacity, consistent with it's mid to late life phase of production operation.

The Northern Fields include the Bunga Orkid Complex consisting of 1 central processing platform (BO-A) and 1 bridge linked wellhead platform (BO-D) as well as 3 additional remote wellhead platforms; BO-B and BO-C in the Bunga Orkid field and BP-A in the Bunga Pakma field (Figure 10.2). The remote wellhead platforms are connected to the Bunga Orkid Complex via a total of 6 subsea pipelines. Processed liquids are pumped to a dedicated Floating Storage and Offloading vessel (FSO Orkid) and dry high $C0_2$ gas is sent to the Bunga Raya Complex via a 54km 24" subsea pipeline for $C0_2$ removal, compression and sales to Peninsular Malaysia and southern Vietnam.

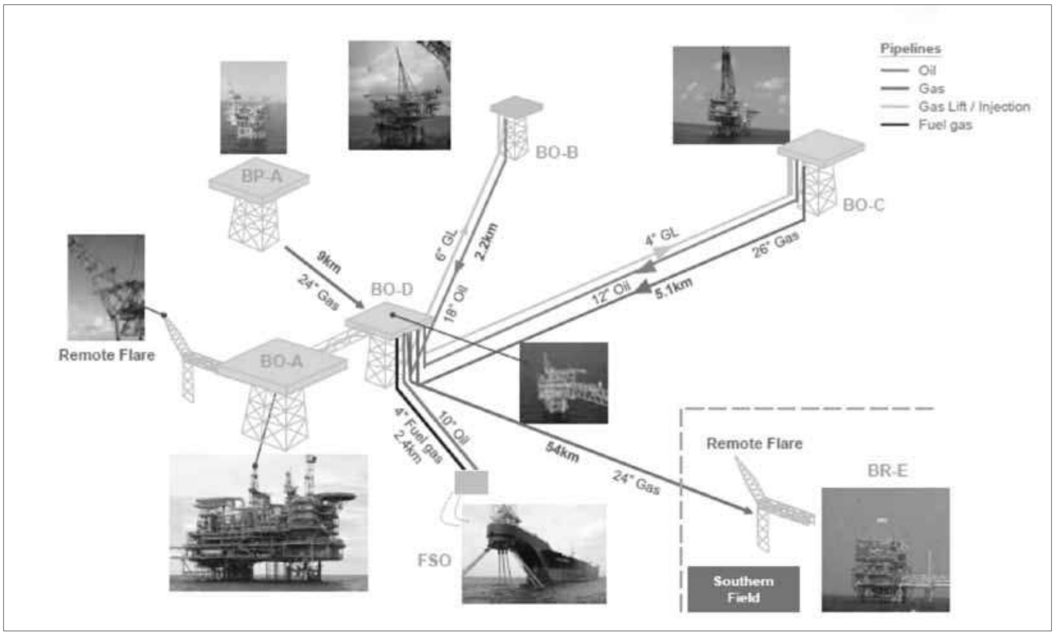

Figure 10.2: Bunga Orkid Complex Facilities Layout

The Bunga Orkid Complex liquid production capacity is 40,000bpd (inclusive of 10,000bpd condensate) and gas export capacity to BR-E is 500 MMscfd. With water treatment capacity of 45,000bpd, gas lift of 150 MMscfd, gas injection of 55 MMscfd and water injection of 40,000bpd. The complex is also equipped with gas and condensate mercury removal units. Bunga Orkid process is operating below capacity producing around 11,000bpd (oil and condensate), and 350 MMscfd gas @ 40% CO_2. There are no topsides process bottlenecks, however the gas and condensate mercury removal units require more frequent absorbent change outs due to higher mercury concentrations than anticipated at design.

The Southern Fields encompasses the Bunga Raya Complex consisting of 1 central processing platform (BR-A) and 3 bridge linked platforms; BR-B wellhead platform, BR-D oil processing and gas compression Mobile Offshore Application Barge and BR-E GPP (gas processing platform) (Figure 10.3). There are a further 5 remote wellhead platforms: BR-C in the Bunga Raya field, BK-A and BK-C in the Bunga Kekwa field, BS-A in the Bunga Seroja field and BT-A in the Bunga Tulip field. The remote wellhead platforms are connected to the Bunga Raya Complex via a total of 16 subsea pipelines. Processed liquids are pumped to a dedicated Floating Storage and Offloading vessel (FSO PM3 CAA). Sales quality gas is metered and sold to Peninsular Malaysia via a 160km 24" pipeline to the Resak Platform and 297km 18" pipeline to Ca Mau in southern Vietnam.

The gas sales pipelines are operated by the respective national oil companies.

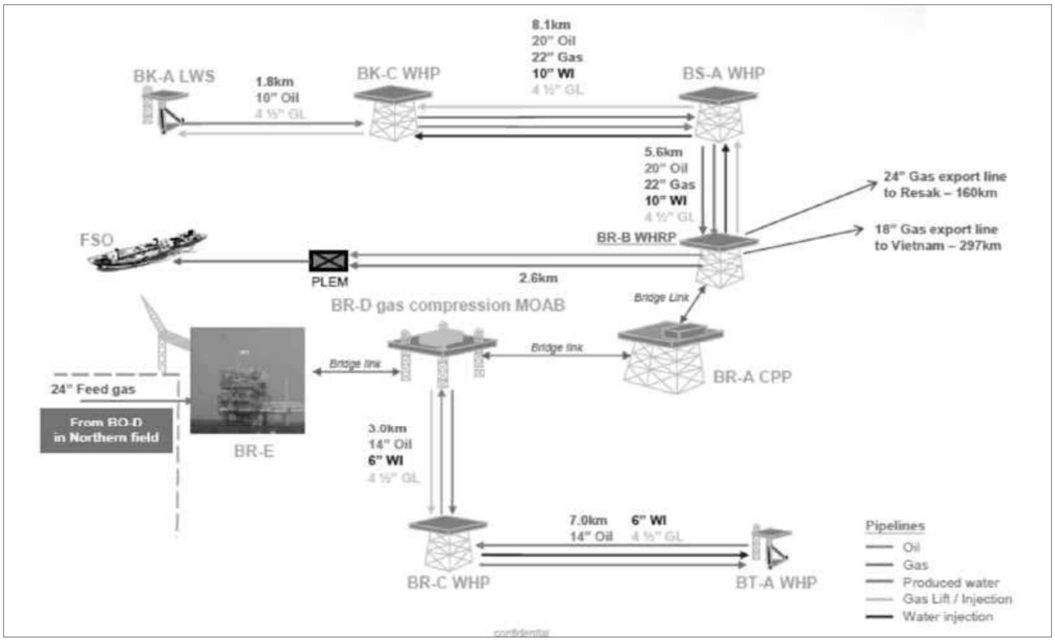

Figure 10.3: Bunga Raya Complex Facilities Layout

The Bunga Raya Complex liquid production capacity is 13,000bpd (including condensate) and gas sales of 320 MMscfd. With water treatment capacity of 88,000bpd, gas lift of 30 MMscfd and water injection of 120,000bpd. The BRE GPP has a feed gas capacity of 680 MMscfd at up to 44.5% CO_2. BR-A is equipped with a gas mercury removal unit in addition to the mercury removal capabilities of BRE GPP. The Bunga Raya complex is operating below capacity producing around 11,000bopd (oil and condensate) and 220 MMscfd gas sales @ 8% CO2. There are no topsides process bottlenecks, however gas lift is limited by pipeline back pressure to remote wellheads and liquid production is limited from BKA and BKC by pipeline back pressure.

PM3 CAA is the most complex and largest producing asset within the Repsol portfolio. The assets are well maintained and in relatively good condition for age and operating environment. Integrity and reliability issues are identified and manageable without significant additional cost or prolonged production outages. Process plants and major equipment was of good industry standard at the time of installation and is supported by the original equipment manufacturers enabling reasonable upgrade costs to support extension of operational life.

Historical HSE performance is similar to most oil and gas operations in Malaysia with no significant issues identified from available data.

Jacket structure integrity is acceptable, except BRD MOAB which may require rectification within the next 2-3 years. Most structures are within design life but will require structural studies to evaluate requirements to extend to end of PSC and beyond. Topsides structure and piping external corrosion is as expected for the age of the assets and well managed on a campaign basis. Sand erosion of flowlines and jumpers is a known issue with ongoing monitoring and repair. There are recognised issues with piping corrosion under pipe supports and insulation which is the focus of a field wide dedicated program.

Most Pipeline Systems are within an acceptable level of integrity. Integrity issues are identified and actively monitored with feasible mitigation/rectification. Pipelines BTABRC14PL and BPABOD24PG recent 2020 IP data identified anomalies which are of immediate threat to the integrity of the systems. Repsol has initiated action to address BPABOD24PG, however the plan for BTABRC14PL was not available at the time of this report.

Six (6) pipelines have relatively short remnant life based on historical intelligent pigging however, re-assessment for remnant life is yet to be updated following recent IP data. Some of these pipelines may require remedial work to ensure integrity to end of PSC. Top of line corrosion due to high CO2 wet fluids is the main concern for internal wall loss. This is managed by active chemical inhibition and pigging however subsea sectional replacements will be required if wall thickness is nearing minimum acceptable levels.

Overall availability in 2019 and 1H 2020 were 3.1% and 3.0% below target for oil and 1.4% both years for gas due to higher unplanned deferment. Reliability of the BRE GPP in the Bunga Raya Complex was a significant contributor to 2018/2020 losses, however these issues have subsequently been rectified. Maintenance compliance is historically high but has reduced in 2019 & 2020 primarily due to a change from Maximo to SAP CMMS, creating a backlog in workorder close out and restrictions in personnel mobilisation due to Covid-19.

10.1.3 Kinabalu Summary

Kinabalu is a low GOR oil field offshore Labuan, East Malaysia in Sabah waters (Figure 10.4). The facilities comprise of two bridge linked platforms. Although not normally manned the facility is visited daily by crew boat from Labuan. There is remote monitoring and control in a dedicated control room at the Labuan Crude Oil Terminal (LCOT) for night monitoring and when weather prevents access.

KNDP-A, installed in 1997, a drilling and production platform is bridge linked to KNDW-D wellhead platform installed in 2017. KNDP-A processes all fluids with stabilised oil exported by a 28km 12" subsea pipeline oil to LCOT via the PCSB operated Samarang Complex. Kinabalu utilises associated gas for fuel and gas lift but has no sales rights. Excess gas is exported to Samarang via 28km 14" subsea pipeline. Produced water is also separated and treated on KNDP-A for disposal offshore. Water injection is by dump flood from a shallow aquifer utilising ESP's with no surface water treatment process.

The subsea oil and gas pipelines to Samarang are included in the Kinabalu PSC and the responsibility of the operator to inspect and maintain.

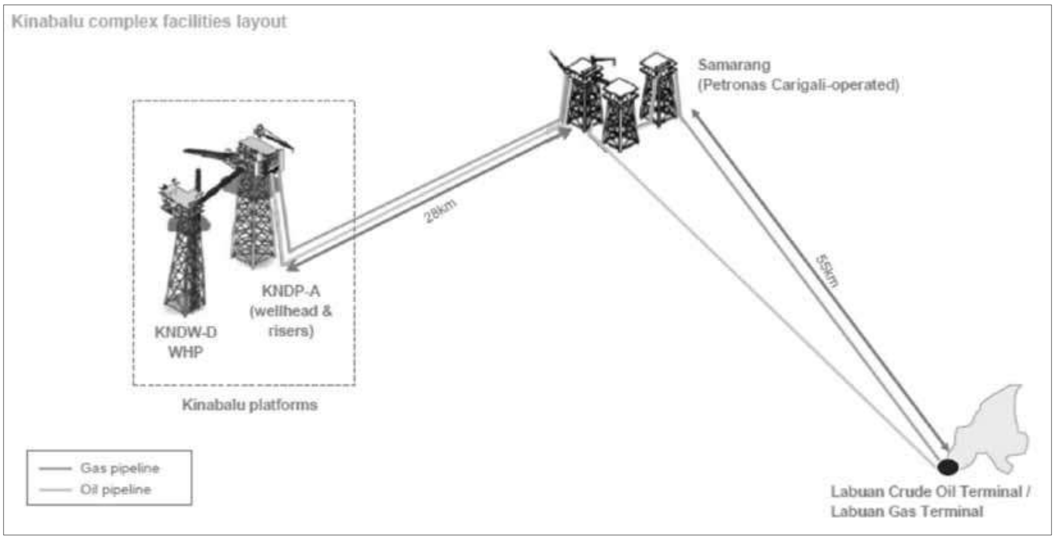

Figure 10.4: Kinabalu Complex Facilities Layout[55]

Kinabalu has total liquid capacity of 60,000bpd with export capacity of 30,000bpd and water treatment of 45,000bpd. Gas processing capacity is 48 MMscfd with LP compression capacity of 23 MMscfd, lift (HP) compression capacity of 13 MMscfd. Current production is limited by liquid handling and gas compression capacity with higher water cut wells shut-in to maximise oil production and higher GOR well shut in to control flare.

There is an ongoing project to debottleneck the liquid and gas processing capacity to 75bpd liquid and 70 MMscfd gas. This will provide oil capacity of 20bpd, produced water treatment of 60,000bpd and gas lift of

[55] *VDR Management Presentation 2020.12vF.pdf - Repsol*

25-30 MMscfd. The liquid debottlenecking has been recently completed. The gas debottlenecking portion was removed from the scope and will be pursued as a separated project.

Kinabalu is a relatively small and simple producing asset. The asset is well maintained and in relatively good condition with the main KNDP-A platform benefiting from recent upgrades to improve liquid process capacity and ongoing work to address obsolete and aging equipment. Integrity and reliability issues are identified and manageable without significant additional cost or prolonged production outages.

Historical HSE performance is similar to most oil and gas operations in Malaysia with no significant issues identified from available data.

There are no jacket structural issues with either KNDP-A or KNDW-D.

Topsides structure and piping external corrosion is as expected for an asset of this age and well managed on a campaign based. There are recognised issues with piping corrosion under pipe supports which is the focus of a dedicated program. Sand erosion of flowlines and jumpers is a known issue with ongoing monitoring and repair. HP compressor pipework and fittings suffer from vibration fatigue resulting in failures and hydrocarbon releases in mid-2020. Repairs were completed however a long-term solution is required to resolve the HP compressor vibration.

Kinabalu pipelines remnant life exceeds the PSC expiry of Dec 2032 however, free spans on both pipelines may be required remediation.

Kinabalu unplanned production loss was above target of 4.7% in both 2019 and 1H 2020 at 8.6% and 5.8%. The main contributors were HP compressor and LP compressor trips, produced water shutdowns, main generator failure and production cutbacks due Samarang gas handling issue. Recent improvement to the produced water system is anticipated to address water handling issues. HP compression reliability and Samarang consistent gas take require resolution to improve production reliability.

10.1.4 South Angsi Summary

South Angsi along with Kuning and Naga Kecil production ceased in 2019 and is in the process of well abandonment and decommissioning. The FSO Angsi operated by MISC and leased by the PSC has been decommissioned and demobilised on 30th March 2020 with no outstanding liabilities to the PSC. Plans are at an advanced stage for well abandonment and the removal and disposal of the South Angsi fixed facilities (Figure 10.5).

Figure 10.5: South Angsi Fixed Facility

The fixed facilities consist of a wellhead jacket with 13 wells and 15 string (11 single string and 2 dual string completions) and a Mobile Offshore Application Barge (MOAB) containing the process plant and equipment. Wells are suspended, facilities flushed, made safe and secure. The facility was left in lighthouse mode on 15 April 2020.

As per PPGUA all 13 wells have SWAP-1 certificates issued on 18 August 2018. There is a 3 years limit to execute P&A from issue of SWAP-1 certificate. Repsol well plug and abandonment cost estimate is US$

25.5 million. Well abandonment is not included in Cess fund and are a PSC cost, falling within the PSC term (December 2025).

The well abandonment will be conducted as a rigless operation and planned in 3 stages. Eleven (11) wells will use the caprock method to isolate hydrocarbon zones, the remaining two (2) isolations are at the reservoir.

1. Remove plugs with Slickline or Coiled Tubing, bullhead cement for reservoir abandonment (2 wells) and cut tubing. Execution planned for March – April 2021. Estimated cost US$ 3.0 million.
2. Hydraulic Workover Unit to retrieve tubing, establish caprock barrier (11 wells), cut and retrieve casing and establish surface plug. Execution planned for April – October 2021. Estimated cost US$ 13.6 million.
3. Cut and retrieve surface 13 3/8" casing and 24/30" conductor id included in the jacket removal scope. Estimated cost UD4.3m.

The South Angsi plug and abandonment plan was presented at WMRC on 24 June 2020 and approved by MPM. The Phase 1 and 2 contract strategy is a lump sum per well to reduce Repsol exposure to a cost overrun. At a meeting on 7 December 2020 with MPM, Repsol informed of a delay in awarding the contract for well P&A to 1 February 2021. Repsol do not anticipate this to have an impact in completion of Phase 1 and 2 P&A activities in 2021.

MPM agree to include recovering the 13 3/8" casing and 24/30" conductor (well P&A Phase 3) as part of the wellhead jacket removal scope. There are synergies between the casing/conductor recovery operations and the jacket removal scope. Including this in the jacket scope removes US$ 4.3 million well abandonment costs in 2022. A separate discussion between Repsol and MPM is to be held regarding applicability of well casing/conductor removal costs being recovered from the Cess Fund.

The facilities abandonment study was competed in July 2020 by an independent consultant. The proposed method is to reverse the MOAB installation by float off and wet tow to yard for disposal. The wellhead jacket will be piecemeal removed and transport to a disposal yard. The class 3 cost estimate (+15% accuracy range, real 2020) is US$ 33.3 million. Execution is planned in 2023. Repsol presented Abandonment Review 2 (P&A and Facilities Decommissioning) to Petronas MPM 28 September 2020. The options to repurpose and reuse the MOAB or sink as an artificial reef were ruled out during option screening. The preferred option for the wellhead jacket is to cut at -55m and leave part of the structure in place as an artificial reef which requires Department of Fisheries approval. Repsol had encouraging initial discussion with DoF. This option has potential to save 10-15% costs.

Facilities abandonment is covered by the Cess Fund. The abandonment Cess Fund stands at is approximately US$ 39 million (actual paid MYR 157 million). There is potential for growth in facilities abandonment costs due to market conditions and unknown events. The PSC must follow Petronas procurement procedures which greatly limits availability of experienced contractors and can lead to a less competitive cost environment. To reduce the risk of cost overrun Repsol is proposing a single EPRD (Engineer, Procure, Remove and Dispose) contract.

10.1.5 Key Findings

10.1.5.1 Platform Structures

There are 17 offshore structure (excluding South Angsi). Two (02) of the installations, KNDP-A and BKA have had their design life exceeded in 2017. Following structural studies KNDP-A operation life has been extended to end of PSC. Structural studies for BKA indicating potential life extension by 10 years to 2027 (end of PSC), however there is potential for this jacket to require remedial work to extend operational life to end of the PSC and further.

The BRD MOAB structure in PM3 South is tilting and flagged as an asset integrity high risk. This houses oil processing, flash gas compression, gas lift compression for process pipework to and from BRE. The proposed solution is to install shim plates to address the tilting and monitor the legs. This issue may require further rectification following the ALE structural studies.

Nine (9) PM3 South installations exceed design life before end of PSC (2027) requiring asset life extension studies in the next 1 – 5 years. Five (5) PM3 North installations reach design life in 2027 and will require studies to extend operational life past end of PSC.

There are no jacket structural issues with either KNDP-A or KNDW-D however the subsea structural inspection has been deferred from 2020 to 2021.

No significant concerns regarding the integrity of topsides structure were evident. Deferment and delays in campaign painting and repair due to Covid-19 and budget reductions in 2020 may result in catch up activities in 2021 and 2022.

10.1.5.2 Platform Topsides Equipment and Rotating Machinery

The topsides processes have high reliability and appears to be well maintained. Repsol utilises a production loss reporting and root cause analysis to identify and prioritise well and equipment issues responsible for deferred production. The highest value issues have been resolved or have an action plan in progress.

Major rotating equipment has high availability and reliability, however three (3) early life failures of Solar turbines at PM3 South maybe the result of inefficiency in the air intake filtration system and will require upgrades and improvements.

Kinabalu HP compressor has low reliability caused by high vibration induced cracking of pipework and pulsation dampeners. This was to be addressed in the gas capacity debottlenecking project which was deferred in late 2020 with no new planned implementation date.

None of the above issue are of major concern but will require resolution to ensure high reliability and availability of the topsides process.

10.1.5.3 Pipelines

Repsol operates thirty-one (31) Pipeline Systems in total from both PM3 and Kinabalu Assets. PM3 CAA accounts for 29 in field pipelines. The gas export pipelines from PM3 CAA to Malaysia and Vietnam are operated by PETRONAS and PetroVietnam respectively.

Most of the Pipeline Systems are still within an acceptable level of integrity, based on the assessed remaining life and planned remedial work. Four (04) of the Pipelines have remaining life until 2023 including one (01) until 2022. One (01) of the Pipelines with remaining life until 2021 had remedial work completed in Aug./Sept. 2020. However, re-assessment for remaining life has yet to be updated.

The main concern is presence of internal and/or external wall loss anomalies along the sealine section requiring costly remediation work, i.e., subsea intervention. The next integrity concern of a lesser degree is the presence of critical free spans which can make the pipeline susceptible to fatigue failure due to vortex induced vibration. It is also to be noted that four (04) gas lift pipelines have suffered some form of mechanical damage due to anchor drag.

Recent 2020 IP data for PM3 pipelines BTABRC14PL and BPABOD24PG identified anomalies which are of immediate threat to the integrity of the systems. Remedial works will need to be planned and executed during the next available opportunity. Repsol has initiated action to address BPABOD24PG, however the plan for BTABRC14PL was not available at the time of this report. It will be important to gain a full understanding of planned activity, scope, timing, and costs prior to assuming operatorship.

Other concerns are mainly associated with wall loss due to internal or external corrosion at topside / riser atmospheric section. These concerns can be suitably addressed by either sectional replacement, engineered wraps or mechanical cleaning and painting, depending to the extent of wall loss.

As the way forward, the readily identified technical concerns will need to be first addressed and to assure their integrity. Subsequently, further degradations or damage mechanisms will need to be reduced to lowest rate possible.

10.2 Introduction

The purpose of the review was to identify any "red flag" items which would prevent Hibiscus making a bid for Repsol's oil and gas assets in Malaysia. In the event there are red flags, to estimate any incremental OPEX which could be incurred to the end of the PSC term 2027 PM3 CAA, 2032 Kinabalu and potential end of economic life 2043 PM3 CAA.

The review was conducted on all facilities in four key areas:

- Jacket structures

- Topsides Static Equipment- pressure containing equipment and piping and safety control systems
- Pipelines
- Topsides rotating equipment

10.2.1 Background

Hibiscus intends to submit a proposal to acquire Repsol's oil and gas producing assets in Malaysia. The proposal will be submitted in March 2021. Repsol provided data within a virtual data room to allow Hibiscus to assess the value of the assets. A dedicated breakout discussion was also held with vendor's technical team.

The review team consisted of personnel with significant experience in assessing the operability and integrity of assets. The team is made up of:

Mike Fox - 36 years' experience in the engineering, operation and maintenance of oil and gas assets in the UK, Malaysia and Australia. He commenced his career as an Operations Engineer with Mobil in the UK sector. His career has included various operational and engineering supervisory and management rolls including Offshore Installation Manager in the UK, Operation Manager PM3 and South Angsi and Asset Manager Kinabalu for Talisman Malaysia and present role as Operations Improvement Lead for SEA Hibiscus North Sabah.

In addition to his offshore operations and technical knowledge and experience, Mike has significant detailed knowledge of the Repsol assets having spent 9 years in senior operations management roles during a period of high activity and growth from 2004 to 2013.

Claus Jensen - Rotating Equipment and Lead Mechanical Engineer with over 35 years local and international experience in the oil and gas industry, during which time he has worked in all of its phases, from pre-FEED concept selection through to operations and has dealt with the full range of rotating equipment and associated ancillaries.

His rotating equipment related knowledge and skills include plant and equipment concept selection, specification, procurement, testing, installation, commissioning, maintenance, and troubleshooting. He has hands on experience in the practical aspects of equipment installation such as lube oil flushing, and alignment. On the theoretical side he is adept in the engineering sciences such as fluid mechanics, thermodynamics, vibrations, and mathematical modelling and is conversant with the ever-evolving body of industry standards and practices.

Kali Doraisamy – Asset Integrity professional with over 19 years local and international experience in integrity and maintenance engineering within international upstream oil & gas operations. Delivered various integrity management frameworks and maintenance management systems for major Operators in UK, Middle-East and South-East Asia. Present role as Lead Integrity with SEA Hibiscus.

He is also fully conversant with Malaysian legislation and regulation, and PETRONAS guidance relating to asset integrity and assurance.

10.2.2 HSSE Background

As a PSC holder, Repsol is subjected to the Laws of Malaysia and the terms and condition of the contract entered with PETRONAS. This includes the use of PETRONAS' definition on HSSE management, the adoption of PETRONAS established procedures, reporting of agreed parameters and access by local authorities/PETRONAS to conduct site inspections and audits.

Three of the important HSSE systems established by PETRONAS and in use by Repsol are:

- PPGUA – PETRONAS Procedures and Guidelines for Upstream Activities
- OSRMS – Offshore Self-Regulatory Management System
- HSEMS – Health Safety Environment Management System

The above three form the operational basis for the conduct of operations and for PETRONAS to inspect and audit upstream operations. Compliance check to OSRMS (at Tier 3 level) is conducted by a joint team of PETRONAS and DOSH (Department of Occupational Safety and Health, Malaysia), while PPGUA compliance check is conducted by PETRONAS through the IOAIA (Integrated Operation Asset Integrity Assurance) and HSEMS audits.

A team of Hibiscus professionals reviewed the data in the VDR with a focus to assess the primary HSSE risks and/ or concerns.

HSSE Performance data between 2016 to 1Q 2020 was incomplete with 2019 not available. There are a notable high volume of Near Miss incidents recorded on an annual basis. There were no details on the incidents or resulting actions. Planned HRA, exposure monitoring and health surveillance activities were fully executed from 2016 to 2019.

To the end of 2019 there was a 20% backlog for the Safety Corrective Maintenance and Safety Preventive Maintenance works indicate that it is possible to further optimise and improve the overall maintenance strategy.

The following concern areas of HSSE Technical (Operation & Strategic) risks were noted:

- Presence of CO_2 and Mercury issues
- Infield pipeline corrosion due to high, wet CO_2
- Not normally present and low levels of H_2S
- Tilting of BRD
- Water treatment & discharge
- The Severity of Encroachment & Fish Bombing incidents are unknown
- Security threats from foreign enforcement agency vessels, if any, due to the proximity of PM3 CAA & Block 46 to International borders is acknowledged

Using the Hibiscus Risk Matrix the asset HSSE risk was evaluated as "Medium to High". However, all risks identified are adequately mitigated by Repsol and Hibiscus can improve this in several areas going forward. The main risks identified are:

A. GHG – PETRONAS target of Zero Emission by 2050. It is noted that five GHG emission reduction project options were evaluated and two projects (BR-E Efficiency Improvement (new membrane type) & Gas Assisted Continuous Flaring) have been endorsed by the regulators for consideration with no obligation at this juncture (4C).

B. Mercury - Mercury in the form produced at PM3 or any other producing field in the Thai Basin is elemental mercury and mercury salts, which if present can build up in the body in the event of excessive exposure and create illness. Thus, moderate impact of occupational health illness is expected in the event of an exposure. However, this is a lower probability event due to Operational controls (3B).

C. SCPM & SCCM – Backlog of overdue maintenance diminishes the Asset Integrity with more physical components working beyond safe operating limits with the potential catastrophic severity. However, the implementation of any reasonable design and maintained facility will manage the probability to a very unlikely level (5A).

D. Presence of foreign enforcement agency vessels, if any, due to the proximity of PM3 CAA & Block 46 to International borders for Right of Way Survey is acknowledged. (5A).

Consequences					Probability				
Severity	People	Asset/Financial	Environment	Reputation	A (1) Very unlikely	B (2) Unlikely	C (3) Possible	D (4) Likely	E (5) Almost certain
5 Catastrophic	Multiple Fatalities	**Massive Damage** Financial loss >USD50 million. Event likely to lead to bankruptcy of HPB	**Massive Effect** Permanent impact on highly valued ecosystems, species or habitat	**Massive international consequence** International public attention. Extensive adverse attention in international media. Mandate to operate revoked	C 5 D	10	15	20	25
4 Major	Single Fatality **PTD, PPD**	**Major Damage** Financial loss >USD10-USD50 million	**Major Effect** Major long term (>5years) impact on ecosystems, species or habitat	**Major national consequence** National public concern. Extensive adverse attention in the national media. Mandate to operate restricted	4	8	A 12	16	20
3 Moderate	**Major injury or health effect** LTI or temporary disability -	**Moderate Damage** Financial loss >USD5-USD10 million	**Moderate Effect** Limited environmental damage Moderate medium term (2-5 years) impact but not affecting ecosystem function	**Moderate localised consequence** National media and/or regional regulatory attention resulting in negative consequence on company operations	3	B 6	9	12	15
2 Minor	**Minor injury or health effect** MTC or RWC	**Minor Damage** Financial loss >USD0.5-USD5 million	**Minor Effect** Minor short term (1-2 years) environmental damage, but no lasting effect.	**Limited consequence** Local media and/or local regulatory attention with limited negative consequence for company operations	2	4	6	8	10
1 Slight	**Slight injury or health effect** No Treatment Case or FAC	**Slight Damage** Financial loss <USD0.5 million	**Slight Effect** Slight and temporary (<1 year) environmental damage localized effect on ecosystem, species or habitat	**Slight effect** Local public awareness but no discernible concern.	1	2	3	4	5
Notes:	PTD: Permanent Total Disability PPD: Partial Permanent Disability LTI: Lost Time Injury MTC: Medical Treatment Case RWC: Restricted Work Case FAC: First Aid Case See explanation table	Direct Cost: Costs attributable to the incident including loss of revenue, repair or restoration costs See explanation table	See explanation table	See explanation table	Theoretically possible but not occurred yet in the industry (not in last 100 years)	Has occurred in the industry (once or twice in last 10 years)	Has occurred once within HPB or many times in the industry (last 5 years)	Could occur in most circumstances in the industry (once per year)	Expected to occur in most circumstances in the industry (multiple occurrences in a year)

Table 10.1: Hibiscus Risk Assessment Matrix

Consequences	
Risk rating	Intervention
16-25	Risk is not tolerable. - Mitigate the Risk by incorporation of control and recovery action(s) to reduce the Risk rating to HIGH or below Incidents and Assurance findings/reports reportable to Group CEO Incident investigation led by Op Co CEO or delegate. Hi Po incident investigation led by Op Co L2
9-15	Risk is tolerable if supported by ALARP demonstration - Undertake risk reduction by applying appropriate control and recovery barriers - Review and approval of ALARP demonstration by Op Co L3 Incidents and Assurance findings/reports reportable to Op Co CEO Incident investigation led by Op Co L3
4-8	Risk is tolerable if supported by ALARP demonstration - Undertake control evaluation - Review and approval of ALARP demonstration by HOD / Op Co L4 - Monitor using procedure or appropriate internal control Incidents and Assurance findings/reports reportable to Op Co L3 Incident investigation led by Op Co L4
1-3	Risk is tolerable - Monitor at operational level using procedure/appropriate internal control - Take corrective action according to availability of resources

Table 10.2: Risk Rating and Required Intervention

10.3 Structural Integrity

The overall operation contains some 18 platforms, 15 in PM3, 2 in Kinabalu and one in South Angsi. The South Angsi platform has ceased production and planning is progressing for removal, this structure has not been included in this review.

The Repsol facilities have an original design life of 20 years, except BP-A with a 15 years design life. At this time only two structures (BK-A and KNDP-A) have exceeded design, however 8 facilities in PM3 South will exceed design life before the end of PSC. A further 4 PM3 North facilities reaching design life at end of PSC in 2027.

No.	Asset	Field	Installation ID	Function	Install (Year)	Design Life (Years)
1.	**PM3**	Bunga Orkid	BO-A	Central Processing Platform	2007	20
2.	**PM3**	Bunga Orkid	BO-B	Wellhead & Riser Platform	2007	20
3.	**PM3**	Bunga Orkid	BO-C	Wellhead & Riser Platform	2007	20
4.	**PM3**	Bunga Orkid	BO-D	Wellhead & Riser Platform	2007	20
5.	**PM3**	Bunga Orkid	BO-E	Flare Jacket	2007	20
6.	**PM3**	Bunga Pakma	BP-A	Wellhead & Riser Platform	2018	15
7.	**PM3**	Bunga Kekwa	BK-A	Wellhead Platform	1997	20
8.	**PM3**	Bunga Kekwa	BK-C	Wellhead & Riser Platform	2003	20
9.	**PM3**	Bunga Raya	BR-A	Central Processing Platform	2003	20
10.	**PM3**	Bunga Raya	BR-B	Wellhead & Riser Platform	2002	20
11.	**PM3**	Bunga Raya	BR-C	Wellhead & Riser Platform	2003	20
12.	**PM3**	Bunga Raya	BR-D	Compression Platform MOAB	2003	20
13.	**PM3**	Bunga Raya	BR-E	Gas Processing / Vent Platform	2005	20
14.	**PM3**	Bunga Seroja	BS-A	Wellhead & Riser Platform	2002	20
15.	**PM3**	Bunga Tulip	BT-A	Wellhead & Riser Platform	2006	20
16.	**Kinabalu**	Kinabalu	KNDP-A	Wellhead Platform	1997	20
17.	**Kinabalu**	Kinabalu	KNDW-D	Wellhead Platform	2017	20

Table 10.3: Summary of Installed Platforms

The objective of the structural review was to capture and present the current condition of the assets based on outcomes of a review exercise from the VDR documents and replies from Repsol. The information presented is expected to give an understanding and awareness of the current condition.

10.3.1 Platform Jackets

There are seventeen (17) operating offshore installations. Two (02) of the installations, BKA and KNDP-A have had their design life exceeded by 2017. The installations were both installed in 1997 with design life of 20 years. For BK-A, phase-1 of its ALE, which is structural related has been completed. Phase-2 of the ALE is to be performed in 2021 which is reported to have been delayed due to a contractual issue.

For KNDP-A, the installation is reported fit-for-service for another fifteen (15) based on the findings from its ALE study. This is subject to implementation of the recommendations and/or mitigations in the study which have been reported complete.

The table below (Table 10.4) details the findings from the integrity review exercise for Offshore Installations. The findings here are those deemed critical with relevant updates, where available.

No.	Installation	Findings	Ref.	Note / Status / Updates
1.	**BRD**	a) Hull tilting due to leak on three (03) topside legs, detected in 2016	[16], [20], [21]	a) Risk assessment for safe continuous operation has been conducted. Installation of temporary online monitoring planned in Q4 2020 b) Installation of shim-plates on all four (04) legs to arrest further movement / tilting. The work is planned for 2021 and budgeted c) Liner-In-Place Analysis performed in 2017-2018. In 2020, ALE study performed including Push-over Analysis which preparation of final report underway. d) UWI and survey monitoring to be executed to extend its life until PSC and further 10 years
2.	**BKA**	a) Fatigue analysis performed by DNV in 2016 (with latest MetOcean data) resulted with twenty-two (22) member-end joints with fatigue life less than 20 years b) Exceeded its design life in 2017	[16], [21]	a) Asset life extension study is reported currently underway with MetOcean data form other Operators in the region being cross-checked. Ultimate Push-Over Analysis is to be conducted b) Linear-In-Place Analysis and Fatigue Analysis were performed in 2016-2017. In 2020, ALE study performed including Push-over non-Linear Analysis which preparation of final report underway. The results indicate that the Jacket is fit-for-service and reliable subject to no further major modifications or load addition c) UWI for 10 joints of sub-structures to extend the life until PSC and further 10 years
3.	**BOA**	a) Scouring of five (05) Jacket piles. First observed in 2010 and subsequent three (03) observations found the scouring progressed and nearing the design limit.	[16]	Remediation planned by placement of cement bag during 2021 Diving Campaign
4.	**PM3 North Jackets**	a) Depleted anodes	[16]	Rectification to be planned base on outcomes of CP readings and analysis from 2020 ROV Campaign
5.	**KNDP-D**	Deferment of scheduled UWI in 2020	[19]	The Jacket was installed in 2017 had its baseline UWI scheduled in 2020. However, it had to be deferred to 2021 due to restriction entry to Sabah caused by pandemic

Table 10.4: Critical Findings – Offshore Platform Jackets

This section presents the reported intervention that had successfully been performed previously via Diving / ROV Campaign. The interventions were performed as scheduled to reinstate the technical integrity of the related facilities / appurtenances.

There were a few planned interventions that had to be deferred due to unforeseen circumstance, [ref.15]. The list of intervention is captured in the table below (Table 10.5).

No.	Scope of Work	Asset / Facility	Ref.	Note / Status / Updates
1.	**Retrofit of cathodic protection anodes**	N/A	[15]	Deferred to 2022 or further depending on results of 2020 Subsea Campaign
2.	**Anomaly rectification in Jacket(s) & Pipeline(s)**	N/A	[15]	-
3.	**Shim-plate installation**	BRD	[20]	Planned for 2021

Table 10.5: Planned Interventions – Jackets

10.3.2 Topsides Structure

Topsides structures are subject to external corrosion. From the limited data available in the VDR topsides structure corrosion does not appear to be more extensive than anticipated in this operating environment. To manage topsides structure corrosion Repsol performs structure inspections of load bearing and tertiary structures. This data is utilised to plan repair and painting work. Structural painting is generally executed on a campaign basis in conjunction with pipework painting and may include a dedicated accommodation vessel.

In the 2020 at PM3 South isolated perforations were found on the boom structures of 4 cranes (BRA West, BRD, BKC and BRC). Three boom repairs are complete with BRC working under reduced load pending repair. This type of finding is not unexpected for offshore topsides structures of this age.

There were no topside structural repairs noted for Kinabalu in the data available in the VDR.

10.3.3 Structure Concerns

Structural studies are planned as part of the Asset Life Extension scope and are included in the 2021 WP&B submission. These studies are important to provide an insight into the structural longevity of the assets past PSC expiry. There was no information available in the VDR regarding existing structural damage to any jacket and jacket structures, with the exception of BRD. BKA jacket has exceed design life and the initial report on structural integrity is being revisited by Repsol. That being the case there are a few issues with PM3 structures worth noting.

BR-D MOAB 3 out of 4 hollow legs leaking subsea. This has resulted in the jacket tilting. This jacket houses oil processing and flash gas and gas lift compression for PM3S also all fluids to and from BR-E pass over BR-D. This is flagged as High Asset Integrity Risk because of critical consequence and probable probability. The proposed solution is to install shim plates to address the tilting and monitor the legs. This issue may require further rectification following the ALE structural studies.

BKA jacket a light-weight structure in stalled in 1997 for early has exceed design life. There is potential for this jacket to require remedial work to extend operational life to end of the PSC and further.

Scouring at BOA jacket legs is a concern and funds were included to rectify this in the PM3 CAA 2021 WP&B submission.

PM3 North Anodes depletion will require addressing with anode replacement however it is unclear if funds have been included in the 2021 WP&B.

There are no jacket structural issues with either KNDP-A or KNDW-D however the subsea structural inspection planned in 2020 is deferred to 2021. This is the first subsea inspection of KNDW-D since installation and an important data point for understand structural integrity.

No significant concerns regarding the integrity of topsides structure were evident in from the data available in the VDR. The 2021 WP&B submission includes a relatively steady spend thought to 2025. There will be catching up on activities deferred due to Covid-19 and budget reductions due to low oil price.

10.3.4 Topsides Equipment Integrity

It has not been possible to assess the integrity of topside process equipment due to unavailability of any information in the VDR. The equipment namely, process piping, pressure vessels and heat exchangers are all expected to be in good condition with no major integrity concerns. The safety critical elements associated with the equipment are also expected to meet the minimum performance requirements.

RLM utilise a risk bases inspection program covering pipework, pressure vessels and heat exchangers. Compliance to inspection plans for this equipment is at an acceptable level, based on IOM reporting to MPM.

10.3.4.1 Topsides Piping and Piping Components

Carbon steel process piping including bolts and flanged connections on production facilities and wellheads are known to suffer external corrosion. Based on limited data available, the external corrosion does not appear to be more extensive than anticipated in this operating environment. Repsol addresses the external corrosion issues Topside by implementing maintenance painting campaign periodically.

A large proportion of PM3 production platforms topsides process piping is either duplex or super duplex stainless steel. This adequately addresses the highly corrosive nature of the wet high CO_2 process fluids.

Sand erosion of flowlines and jumpers is a known issue in both PM3 and Kinabalu and registered as a Medium Integrity Risk by Repsol. The proposed mitigation is an annual spend to replace pipework reaching minimum wall thickness.

Corrosion under pipe supports is raised as High-Medium Integrity Risk for PM3 and Kinabalu. A campaign over 2000 to 2023 to address this issue has been initiated but the start delayed due to Covid-19 movement restrictions.

Certain sections of PM3 process piping are insulated for heat preservation or personal protection. However, with this application, the piping is susceptible for under insulation corrosion. This has been identified as a High-Medium Integrity Risk with recommended mitigation plan over 2020 to 2023 at both Bunga Raya and Bunga Orkid complexes. The start of this campaign has been delayed due to Covid-19.

Kinabalu HP compressor pipework and fittings suffer from vibration fatigue. This is evaluated as a Medium Integrity Risk. Following failures and hydrocarbon releases in mid-2020 repairs were completed, however the gas debottlenecking project which includes addressing the HP compressor vibration issue has been deferred to an unspecified date. The possibility of vibration induce failures will require monitoring until a permanent solution is implemented.

The use of specialised wrapping is a standard mode of managing pipework external corrosion and pipework leaks in the industry both as a short-term and long-term solution. No data was available on Repsol's main approach to manage the application and control of pipework wrapping. SEA Hibiscus experience in North Sabah produced detailed procedures for suitability, application, inspection and control of pipping wraps. Upon assuming operatorship of Repsol facilities, it is recommended that Hibiscus revisit the philosophy as used by Repsol for compliance with SEA Hibiscus Sdn Bhd ("SEAH") North Sabah procedures.

10.3.4.2 Major Static Equipment

Very little data was available regarding static equipment in the VDR. Repsol has a variety of pressure vessels from high pressure separators and scrubbers, very high temperature Memguards and waste heat recover vessels to low pressure drain vessels and very low temperature refrigeration vessels. Specific to the Malaysian Upstream environment, offshore pressure vessels require individual Equipment Integrity Assessment Certificate (EIAC) for continued operation. This is stated under OSRMS para 1.1.2 and 1.1.3.

No vessel integrity issues are recorded in the Repsol Integrity Risk Assessment however it was noted that several vessel internal inspections at PM3 were removed from the 2020 turnaround campaign following a risk review and replaced with external inspections. It is unclear if this was a one-off change or an indication of a move to reduce the frequency of internal inspection where possible.

10.3.4.3 Major Rotating Equipment

Repsol operates a fleet of multi-make, multi-model rotating equipment, driven by the operating conditions at the time the equipment was specified and purchased. The makes and models are widely used in the oil and gas industry. The fleet is primarily made up of with Solar, Rolls Royce and Siemens turbine drivers and Caterpillar gas engines at Kinabalu and a mix of Dresser, Kawasaki, Ebara and Rolls Royce gas compressors.

Information for rotating equipment was extremely limited and was presented on a collective basis. No equipment list or database was available, nor work order history.

The major processing equipment in PM3 South was installed in 2003 on BRA CPP and BRD MOAB platforms with the BRAU extension to BRA housing additional water injection, and BRE GPP & vent jacket were added in 2005. PM3 North processing equipment was installed in 2006 on BOA CCP platform.

Kinabalu processing equipment was installed in 1997 on KNDP-A an integrated wellhead and processing platform. Produced water treatment and disposal was added in 2015.

The following summarises the production data for over the second half of 2019 (Table 10.6).

		Approved Target / Limit	Actual
PM3CAA	Crude - Mbopd	18.2	16.6
	Gas Sales - MMscfd	257	244
	Condensate - Mboepd	4.7	4.5
	Flaring / Venting - MMscfd	4.8 / 263	3.9 / 208
	UPC MYR/boe	38.2	35.8
KNB	Crude - Mbopd	14.6	14.9
	Gas Sales - MMscfd	20	30
	Condensate - Mboepd		
	Flaring / Venting - MMscfd	6.3	8.3
	UPC MYR/boe	34.4	29.4

Table 10.6: 2H 2019 Production Statistics

PM3CAA is predominantly a gas produced contributing 89% of the total gas for both PSC's and around 58% of the total liquids.

Although there was no equipment list available the following attempts to outline what major equipment is installed based on available information in the VDR (Table 10.7).

	Duty	Units	Make/Model	Capacity	First Installed
PM3 North BOA					
Compressor	Gas Booster	2 x 100%	Solar Titan 130 turbine	500 MMscfd	2006
Compressor	Gas Injection/Lift	2 x 100%	Solar Mars 100 turbine	70 MMscfd	2006
Compressor	Flash Gas	2 x 50%	Solar Mars 90 turbine		2006
Compression	LP Gas	1 x 100%	Electric motor		2006
Pump	Oil Export	2 x 100%	Electric motor		2006
Pump	Sea Water Lift	2 x 100%			2006
Pump	Water Injection Feed Pump			633 m3/h	2006
Pump	Water Injection	2 x 50%		152.4 m3/h ea	2006
Pump	Fire Water				2006
Power Generation	Main Power	3 x 100%	Solar Taurus 70 turbine	6 MW each	2006
Power Generation	Emergency Power				2006
PM3 South BRA					
Compression	Flash Gas	1	Solar Taurus 60 turbine	45 MMscfd	2003
Compression	Flash Gas	1	Solar Taurus 60 turbine	45 MMscfd	2003
Compression	Export	2 x 100%	RR RB211 turbine	320 MMscfd	2003
Pump	Oil Transfer	2 x 100%	Electric motor		2003
Pump	Sea Water Lift	2 x 100%			2003
Pump	Water Injection Feed Pump				2003
Pump	Water Injection				2003

	Duty	Units	Make/Model	Capacity	First Installed
Pump	Fire Water				2003
Power Generation	Main Power	3	Solar Taurus 60 turbine	4.2 MW each	2003
Power Generation	Emergency Power				2003
PM3 South BRD					
Compression	Flash Gas	1	Solar Taurus 60 turbine	50 MMscfd	2003
Compression	Lift Gas	1	Solar Taurus 60 turbine	70 MMscfd	2016?
Power Generation	Main Power	1	Solar Taurus 60 turbine	4.2 MW	2003
PM3 South BRE					
Compression	Permeate Gas	3	Solar Titan 130 / Ebara compressor		2005
Compression	Overhead Gas	1	Electric motor / Arial Reciprocating compressor		2005
Compression	Refrigeration	1	Solar Centaur 50		2005
Pump	Fire Water				2005
Power Generation	Main Power	2	Solar Taurus 60 turbine	4.2 MW each	2005
Power Generation	Emergency Power				2005
Kinabalu KNDP-A					
Compression	LP Gas	1	Electric motor	23 MMscfd	1997
	HP Gas	1	Cummings Gas Engine / Siemens Dresser reciprocating compressor	13 MMscfd	1997
Pump	Oil Transfer	2 x 100%	Electric motor / YY pump	30 Mbopd each	1997
Pump	Sea Water Lift				
Pump	Downhole Submersible Water	1	Schlumberger		
Pump	Oil Reject	3 x 50%			
Pump	Fire Water				
Power Generation	Main Power	2 x 100%	Siemens turbine		1997
Power Generation	Emergency Power				

Table 10.7: Summary of Major Equipment Installed by Platform

10.3.4.3.1 Gas Turbine Compression

It is worthwhile at this point to clarify terms, sometimes used interchangeably. Availability is defined as the fraction of time that an item of equipment or a system is available for service. This is the time it is operating or is in a fit state of standby readiness. Downtime, either planned or unplanned, reduces availability. Generally, this calculation is performed using yearly performance.

Reliability is the probability that an item of equipment or a system is available for service over a defined period. For example, an annual reliability of 95% for a pump means that there is a 95% chance that the pump will operate or be fit for operation over the year. In the short term everything has a very high reliability and in the very long term zero reliability.

The following figures show the availability figures for gas turbine compression using Solar and Rolls Royce packages on the PM3 BRA, BRD, BRE, and BOA facilities (Table 10.8). There are generally no surprises here with the values lying within the normal range. An exception is TC2920 on BRD which has shown figures in the 80's over 2019 and 2020. This is not shown on its partner machine TC2920.

Locn	Unit	Tag	Availability 2018	Availability 2019	Availability 2020
BRA	Solar Taurus 60	TC2310	97.89	92.05	97.22
BRA	Solar Taurus 60	TC2315	97.77	96.20	96.23
BRA	Rolls Royce RB211	TC2410	92.83	97.08	95.56
BRA	Rolls Royce RB211	TC2510	98.42	95.67	95.08
BRD	Solar Taurus 60	TC2330	96.13	95.89	93.89
BRD	Solar Taurus 60	TC2920	98.45	**87.77**	**84.98**
BRE	Solar Titan 130	TC9510	86.46	97.79	97.24
BRE	Solar Titan 130	TC9520	93.19	98.18	97.02
BRE	Solar Titan 130	TC9530	98.71	98.26	97.58
BRE	Solar Centaur 50	TC9304	89.06	94.50	94.69
BOA	Solar Mars 90	TC2300A	98.96	98.14	97.18
BOA	Solar Mars 90	TC2300B	95.17	96.59	96.17
BOA	Solar Titan 130	TC2410A	98.96	98.43	99.30
BOA	Solar Titan 130	TC2410B	97.75	96.94	98.30
BOA	Solar Mars 100	TC2910	99.37	96.59	97.91

Table 10.8: Gas Turbine - Compression Availability

10.3.4.3.2 Gas Turbine Power Generation

The following figures show the availability figures for gas turbine generation using Solar packages on the PM3 BRA, BRE, and BOA facilities (Table 10.9). There are generally no surprises here with the values lying within the normal range.

Locn	Unit	Tag	Availability 2018	Availability 2019	Availability 2020
BRA	Solar Taurus 60	TG8010	97.71	97.54	98.00
BRA	Solar Taurus 60	TG8030	98.15	92.90	95.46
BRA	Solar Taurus 60	TG8050	98.81	97.79	98.26
BRE	Solar Taurus 60	TG8010	97.93	97.50	97.48
BRE	Solar Taurus 60	TG8010	97.93	96.38	96.83
BOA	Solar Taurus 70	TG8010	97.88	92.51	90.69
BOA	Solar Taurus 70	TG8030	90.53	98.72	98.48
BOA	Solar Taurus 70	TG8050	91.42	98.05	97.87

Table 10.9: Gas Turbine – Power Generation Availability

10.3.4.3.3 Major Rotating Maintenance

Little information was available on rotating equipment maintenance within the information provided in the VDR. At the time of writing no information on maintenance programs was available for PM3CAA or Kinabalu.

Repsol advised that lube oil analysis and vibration monitoring are performed as part of a predictive maintenance program. Both lube oil analysis and vibration monitoring were scheduled on bi-monthly basis, however in the cases where no significant historic deviations were found the frequency of these were revised to a quarterly basis. The lube oil analysis and vibration monitoring re executed by external services.

There was no available information on the ratio of preventative to corrective maintenance available in the VDR.

Data from the KNDP-A ALES & Cost Report, although rather broad brush, gives corrective maintenance figures. These suggest the following:

- Compression is the largest contributor – 34%
- Power generation is the next largest contributor – 13%
- Pumps contribute – 11%
- Fan systems are problematic the issues being the usual rolling element bearing and vee belt failures

The following major maintenance contracts are in place (Table 10.10). These appear to cover both PM3 and Kinabalu operations and all the major equipment scope. One area which is not apparent though is probably covered within the more general contracts such as Turcomp is the maintenance of compressors.

It can be seen 4 of the 10, including the Caterpillar, Solar, and Rolls Royce Service Agreements and LTSA's, are due for renewal this year so a successful bid would need to hit the ground running with these.

Vendor	Contract Name	Renewal Due	Notes
Tractors Petroleum Services Sdn Bhd	Provision of Caterpillar Diesel Engine Parts and Services	19/8/21	
Turboservices Sdn Bhd	LTSA for Solar Turbines	15/9/21	Two contracts one in US$ and the other in MYR are in place
Advance Gas Turbines Solutions	LTSA for Provision of Turbomachinery Maintenance Services – Rolls Royce Gas Turbines	15/9/21	Three contracts in MYR, US$ and GBP are in place
Enserv	Contract Extension – Provision for Repair Services including Testing and Supply of Parts for Flowserve	27/11/21	Not clear if this applies to the pumps
Itses Group Sdn Bhd	HP Compressor Parts and Services for KNB	17/7/22	
Firm Synergy	Provision of Condition Based Monitoring	5/8/22	
Enserv Sdn Bhd	Provision of OEM Flowserve Ingersoll Dresser Pumps for Kinabalu Platform	6/9/22	
MIE Industrial Sdn Bhd	Provision of 6.6 kV Alternator Maintenance	27/10/22	
OGPC Sdn Bhd	Price Agreement for Supply of Parts and Call-Out Services for Clyde Union and Girdlestone Pumps	29/11/23	
Sanggul Emas Sdn Bhd	Sundyne Pumps and Compressors Partts and Services	17/2/24	
Turcomp	Provision of Rotating Equipment Maintenance	9/11/24	

Table 10.10: Major Maintenance Contracts

10.4 Pipelines Integrity

Repsol operates thirty-one (31) Pipeline System in total from both PM3 and Kinabalu Assets as tabulated below (Table 10.11). PM3 accounts for 29 in field pipeline. The gas export pipelines to Malaysia and Vietnam are operated by PETRONAS and PetroVietnam respectively. Kinabalu has no in field pipelines but is operationally responsible for the oil and gas export pipelines to Samarang.

No.	Asset	Field	Pipeline ID	Function	From	To	Install (Year)	Design P (barg)	MAOP (barg)	Size (in)
1.	PM3	Bunga Orkid	BOD-BRE-24EG	Gas Trunkline	BO-D	BR-E	-	92.5	92.5	24
2.	PM3	Bunga Orkid	BOC-BOD-24/26PG	Produced Gas	BO-C	BO-D	-	60.7	55.1	24
3.	PM3	Bunga Pakma	BPA-BOD-24PG	Produced Gas	BP-A	BO-D	-	-	-	24
4.	PM3	Bunga Orkid	BOD-BOB-06GL	Gas Lift	BO-D	BO-B	-	-	-	6
5.	PM3	Bunga Orkid	BOD-BOC-04GL	Gas Lift	BO-D	BO-C	-	190.5	173.2	4
6.	PM3	Bunga Orkid	BOD-FSO-04FG	Fuel Gas	BO-D	FSO PM3	2008	-	11.1	4
7.	PM3	Bunga Orkid	BOB-BOD-18PL	Produced Gas	BO-B	BO-D	2008	-	12.1	18
8.	PM3	Bunga Orkid	BOC-BOD-12PL	Oil	BO-C	BO-D	-	-	16.3	12
9.	PM3	Bunga Orkid	BOD-FSO-10EC	Oil	BO-D	FSO PM3	2008	-	9.8	10
10.	PM3	Bunga Kekwa	BKC-BSA-22PG	Produced Gas	BK-C	BS-A	2003	100	64.5	22
11.	PM3	Bunga Seroja	BSA-BRB-22PG	Produced Gas	BS-A	BR-B	2003	100	64.5	22
12.	PM3	Bunga Kekwa	BKC-BKA-04GL	Gas Lift	BK-C	BK-A	2003	-	138.0	4
13.	PM3	Bunga Seroja	BSA-BKC-04GL	Gas Lift	BS-A	BK-C	2003	-	138.0	4
14.	PM3	Bunga Raya	BRB-BSA-04GL	Gas Lift	BR-B	BS-A	2003	-	138.0	4
15.	PM3	Bunga Raya	BRD-BRC-04GL	Gas Lift	BR-D	BR-C	-	-	-	4
16.	PM3	Bunga Kekwa	BKA-BKC-10PL	Oil	BK-A	BK-C	2003	-	23.1	10
17.	PM3	Bunga Kekwa	BKC-BSA-20PL	Oil	BK-C	BS-A	2003	-	23.1	20
18.	PM3	Bunga Seroja	BSA-BRB-20PL	Oil	BS-A	BR-B	2003	70	23.0	20
19.	PM3	Bunga Raya	BRB-FSO-10EC	Oil	BR-B	FSO Orkid	2003	-	12.8	10
20.	PM3	Bunga Raya	BRC-BRD-14PL	Oil	BR-C	BR-D	2003	-	24.6	14
21.	PM3	Bunga Tulip	BTA-BRC-14PL	Oil	BT-A	BR-C	2006	-	79.4	14
22.	PM3	Bunga Raya	BRB-FSO-06FG	Fuel Gas	BR-B	FSO Orkid	2003	-	17.2	6
23.	PM3	Bunga Raya	BRC-BTA-04GL	Gas Lift	BR-C	BT-A	2006	-	138.0	4
24.	PM3	Bunga Raya	BRD-BRC-06WI	Water - Inj.	BR-D	BR-C	2005	147	106.0	6
25.	PM3	Bunga Seroja	BSA-BKC-10WI	Water - Inj.	BS-A	BK-C	2005	147	106.0	10
26.	PM3	Bunga Raya	BRB-BSA-10WI	Water - Inj.	BR-B	BS-A	2005	147	106.0	10
27.	PM3	Bunga Raya	BRC-BTA-06WI	Water - Inj.	BR-C	BT-A	-	147.6	117.2	6
28.	PM3	Bunga Raya	To-be-advised	Gas Export	BR-B	Resak	-	-	-	24
29.	PM3	Bunga Raya	To-be-advised	Gas Export	BR-B	Vietnam	-	-	-	18
30.	Kinabalu	Kinabalu	PL_311A	Oil	KNDP-A	SMG-A	1997	93	93.0	12
31.	Kinabalu	Kinabalu	PL_312	Produced Gas	KNDP-A	SMG-A	1997	93	93.0	14

Table 10.11: Summary of Pipelines

This section aims at identifying concerns and the extent of work required to maintain the integrity of the pipeline system until at least end of PSC or potential end of economic field life. This review is based on available data in the VDR and replies from Repsol.

10.4.1 Pipeline Integrity Findings

The Pipeline Systems associated with BK-A are reported to have had their design life exceeded in 2017. These are 10-in process liquid and 4-in gas lift pipeline. Phase-1 ALE (Asset Life Extension) study for the Pipeline System is reported to have been completed in 2020. No details available pertinent to the study and if the recommendations and/or mitigations from the outcome of the study have been completed.

The two (02) Pipeline Systems associated with KNDP-A are also likely to have had their design life exceeded. However, no details available if the Pipeline System were part of the completed ALE performed for the installation – KNDP-A.

The table below details the findings from integrity review exercise for Pipeline System (Table 10.12). The findings captured are those deemed critical, determined from past experience, engineering judgement and theoretical knowledge. Any updates or latest status as reported are also captured, where available.

No.	Pipeline_ID	Findings	Ref.	Note / Status / Updates
1.	**BOD-BRE-24EG**	a) An internal mill anomaly with 49% metal loss located at log-distance 4.555m, likely at Topside pipework/riser at BO-D end b) An internal corrosion anomaly with highest wall loss of 35% located at log-distance 35856.084m	[1]	
2.	**BOC-BOD-24/26PG**	a) An external corrosion cluster anomaly with highest wall loss of 47% located at log-distance 5315.16m	[2]	
3.	**BOD-FSO-10EC**	a) Sixty-one (61) Internally formed corrosion pits along its sealine section upstream of PLEM; between log-distance 2441.69m and 2454.16m with the deepest one suffered 31.3% wall loss b) An external corrosion anomaly with highest (calculated) wall loss of 38.6% located at log-distance 1.48m, possibly within launcher facility	[3]	
4.	**BKC-BSA-22PG** **BSA-BRB-22PG**	a) Susceptibility of the Pipeline Systems to Top-of-Line (ToL) corrosion, evident along its first 3km section. The highest suffered wall loss due to this phenomenon was 29%, for a featured located at log-distance 75.13m and 76.32m	[4]	
5.	**BRB-BSA-04GL** **BSA-BKC-04GL** **BKC-BKA-04GL**	a) Two (02) metal loss external corrosion anomalies with calculated wall loss up to 78.8% and 54.3% detected at log-distance 4805.6m and 4788.73m respectively (ILI of Nov. 2014), possibly along sealine section near BS-A end b) ILI performed in 2020 detected three (03) metal loss anomalies exceeding 50% wall loss. It was not reported if the features were internal, external or both. Site-verification with manual UT was reported to have been completed and resulted 26%. It is a concern due to significant discrepancies between measured wall thickness by UT Tool and manual UT	[5], [18]	An external corrosion anomaly with wall loss up to 64.1% located at BKC export riser (under I-Tube) is planned for rectification in 2021
6.		a) Reported remnant life of until 2023 based on ICR (Internal Corrosion Rate) at BSA-BKC Pipeline section, approximately 5.1km from BSA Platform b) Reported to have risks of damage due to 3rd party	[14]	Planned IP of 2020 completed in Sept. and final report yet to be received.

No.	Pipeline_ID	Findings	Ref.	Note / Status / Updates
7.	BSA-BKC-04GL	a) One (01) among four (04) Pipelines suffered displacement due to anchor drag	[15], [16]	The planned remediation by placement of concrete mattress has been deferred to 2022, subject to its condition from 2020 Subsea Campaign
8.	BKA-BKC-10PL	a) An external corrosion anomaly with highest calculated wall loss of 61.8% located at log-distance 11.31m, possibly along its riser at BK-A end b) An internal corrosion anomaly with 50.6% wall loss located at log-distance 75.30m, likely along its sealine section close to BK-A end	[6], [18]	Lowest remaining wall thickness measured 3.98mm at splash-zone. Temporary repair completed in 2020 and permanent repair is planned for 2021. The cost for the work has been budgeted.
9.	BKA-BKC-10PL	a) Reported remnant life of until 2023 on ICR (Internal Corrosion Rate) at BKA expansion spool b) Subjected to threats from ToL (Top-of-Line) corrosion	[14]	a) It is reported that the primary mitigation by bi-weekly spray-pigging is in place b) Consideration of expansion spool replacement / repair with insulation during the next diving campaign
10.	BKC-BSA-20PL	a) An external corrosion anomaly with highest calculated wall loss of 49.6% located at log-distance 13.20m, possibly along its riser at BK-C end b) An internal corrosion anomaly with 31.6% calculated wall loss located at log-distance 72.21m, likely along its sealine section close to BK-C end	[7]	
11.		a) Reported remnant life of until 2022 based on ICR (Internal Corrosion Rate) at BSA-BKC subsea Pipeline, approximately 5.1km from BSA Platform b) Subjected to threats from ToL (Top-of-Line) corrosion	[14]	a) It is reported that the primary mitigation by bi-weekly spray pigging is in place b) Consideration of expansion spool replacement / repair with insulation during the next diving campaign c) ILI planned in 2021 is reported to determine the insulation requirement
12.	BRC-BRD-14PL	a) An external corrosion anomaly with highest calculated wall loss of 38.6% located at log-distance 12.26m, likely along its riser at BR-C end	[8]	
13.	BTA-BRC-14PL	a) An internal corrosion anomaly with 87.8% calculated wall loss located at log-distance 85.45m, possibly along its sealine section neat BT-A end (ILI of 2016) b) Another internal corrosion anomaly with 77% calculated wall loss located at log-distance 87.42m, possibly along its sealine section near BT-A end (ILI of 2016) c) An external metal loss corrosion anomaly with 49.7% calculated wall loss located at log-distance 11.30m, possibly along its riser at BT-A end (ILI 2016)	[9]	Damaged Neoprene coating removed for detailed inspection in Feb. 2020. Reported no immediate integrity concern. Latest inspection in Nov. 2020, at the repaired location was reported to have suffered no significant coating breakdown
14.		a) Reported remnant life of until 2023 based on ICR (Internal Corrosion Rate) of BRC expansion spool b) Subjected to threats from ToL (Top-of-Line) corrosion	[14], [18]	a) Planned IP of 2020 completed in Sept. and final report yet to be received b) Consideration of expansion spool repair by installation of insulation cover during the next diving campaign, subject to findings from the latest IP c) An expansion spool was replaced in Oct. 2017 (no details available). d) Six (06) field joints are un-insulated and reported to be susceptible for ToL corrosion. However, the IP completed in 2020 reported that the joints were of no major findings.

No.	Pipeline_ID	Findings	Ref.	Note / Status / Updates
15.	**BRC-BTA-04GL**	a) There were twenty-four (24) dents to had been reported, ranging between 1% to 5.2% of OD	[10]	
16.		a) Reported to have experienced "displacement" due to anchor drag and suffered minor kink based on 2014 ROV inspection	[14]	
17.		a) One (01) among four (04) Pipelines suffered displacement due to anchor drag	[15], [16]	The planned remediation by placement of concrete mattress has been deferred to 2022, subject to its condition from 2020 Subsea Campaign
18.	**PL_311A**	a) Internal metal loss corrosion anomalies with ERF > 1.0, identified during ILI in Apr. 2014 b) An internal metal loss corrosion anomaly with wall loss of 52% located at SMG-A, identified during ILI in Apr. 2014 c) Confirmation that ROSEN used an incorrect safety factor in ERF calculation that resulted with thirteen (13) anomalies with ERF close to 1.0; i.e., between 0.95 and 0.99, which are critical	[11]	Planned IP of 2020 completed and final report yet to be received
19.		a) Presence of seven (07) free spans that have been planned for rectification as part of ALE (Asset Life Extension)	[12]	
20.		a) Free span analysis for the entire pipeline	[12]	
21.		a) The need to perform strength & fatigue analysis at crossing has been identified as part of KNDP-A ALE	[12], [13]	Initial plan was to have the study performed in 2018 but has been deferred due to contract unavailability
22.		a) The need to perform strength & fatigue analysis for risers has been identified as part of KNDP-A ALE		
23.	**PL_312**	a) Presence of seven (07) free spans that have been planned for rectification as part of ALE (Asset Life Extension)	[12]	
24.		a) Free span analysis for the entire pipeline	[12]	
25.		a) The need to perform strength & fatigue analysis at crossing has been identified as part of KNDP-A ALE	[12], [13]	Initial plan was to have the study performed in 2018 but has been deferred due to contract unavailability
26.		a) The need to perform strength & fatigue analysis for risers has been identified as part of KNDP-A ALE		
27.	**BRD-BRC-04GL**	a) Reported remnant life of until 2021 based on ECR (External Corrosion Rate) at underneath of subsea clamp of Riser at BRD.	[14], [18]	a) The planned remediation work by removing the existing clamp and replacement with retrofit clamp is reported to have been completed during diving campaign in Aug/Sept. 2020 shut-down. The retrofit clamp was installed at location slightly higher than its original location. No wall loss reported, based on NDT wall thickness measurement and results of IP of 2014. The original clamp area had its coating reinstated and wrapped. b) No updates if remnant life assessment has been revisited with completion of the remediation work

No.	Pipeline_ID	Findings	Ref.	Note / Status / Updates
28.		a) One (01) among four (04) Pipelines suffered displacement due to anchor drag	[15], [16]	The planned remediation by placement of concrete mattress has been deferred to 2022, subject to its condition from 2020 Subsea Campaign
29.	BKC-BKA-04GL	a) One (01) among four (04) Pipelines suffered displacement due to anchor drag	[15], [16]	The planned remediation by placement of concrete mattress has been deferred to 2022, subject to its condition from 2020 Subsea Campaign
30.	BOD-FSO-04FG	a) Reported remnant life of until 2026 based on ICR (Internal Corrosion Rate) from IP of 2012	[14]	Planned IP of 2020 completed in June and the highest wall loss anomaly reported was 54%, located at FSO riser – restricted area Both Inspection verification and rectification work planning are reported underway
31.	BRD-BRC-06WI	a) Presence of thirteen (13) spans with one (01) to have exceeded the maximum allowable length	[14]	
32.	BOD-BOB-06GL	a) Free span of the Pipeline between KP 1.563 and KP 1.577	[16], [17]	Rectification planned during Diving Campaign of 2021
33.	??	Past poor performance of SDV-1025 during its periodic function test in 2016 and 2017. The failure of the valve was reported due to "actuator jammed open"	[13]	Reported to have remediation work performed in 2017, no details available. Valve proposed for replacement

Table 10.12: Integrity Review – Pipelines Summary

There are two (02) PLEMs (Pipeline-End Manifolds), one (01) each in PM3 South and North. The PLEMs are positioned at the end of the fixed subsea pipe from BRA and BOA and the start of the flexible rise to FSO PM3 CAA and FSO Orkid. No integrity related information has been received. Thus, the integrity review exercise for the PLEMs shall be performed at later stage once relevant information available.

10.4.2 Pipelines Maintenance

Maintenance activities are carried-out as part of integrity management strategy of Pipeline Systems. The activities are performed periodically, tasked under preventive maintenance plan and managed via CMMS (Computerised Maintenance Management System). Some of the activities are as follows:

- Operational pigging
- Fabric maintenance
- Insulation inspection and replacement
- Chemical treatment

Top of line corrosion is a common feature in PM3 due to wet high CO_2 fluids. This is managed though corrosion inhibition injection and routine maintenance pigging. The effectiveness of the corrosion management is evaluated via regular IP allowing improvements to the strategy and planning of repair work.

Following the outcomes of maintenance and inspection activities, the critical findings have been addressed by remedial work / intervention. Repsol has performed some remedial / intervention works vis diving campaign in 2017. The completion of the tasks has reinstated the technical integrity of the System assuring that the associated risks are as-low-as reasonably practicable (ALRAP)

However, it is also to be noted that a few of the planned interventions had to be deferred due to changes in remediation approach.

No.	Scope of Work	Asset / Facility	Ref.	Note / Status / Updates
1.	**Retrofit of cathodic protection anodes**	N/A	[15]	Deferred to 2022 or further depending on results of 2020 Subsea Campaign
2.	**Anomaly rectification in Jacket(s) & Pipeline(s)**	N/A	[15]	-
3.	**Insulation cover rectification**	BKC-BSA-20PL	[15]	-
4.	**Retrofit of anode skid**	KNDP-A	[17]	Twenty-four (24) anode sleds were successfully connected to the installation
5.	**Free span rectification**	PL_311A	[17]	One (01) location of free span rectified as planned
6.	**Free span rectification**	PL_312	[17]	Five (05) locations of free span rectified as planned
7.	**Free span rectification**	BRC-BTA-06WI	[17]	One (01) location of free span rectified as planned
8.	**Insulation cover installation**	BTA-BRC-14PL	[17]	The installation was intended to arrest further deterioration due to wall thinning. Only one (01) oo5 installed.

Table 10.13: Planned Interventions - Pipelines

10.4.3 Pipeline System – Remnant Life

The Tables below (Table 10.14, Table 10.15 and Table 10.16) detail the current integrity related issues and assessed remnant life of Pipeline Systems in PM3 and Kinabalu as presented in IOM data packages.

Four (04) of the Pipelines are with remnant life of until 2023 including one (01) until 2022. One (01) of the Pipelines with remnant life of until 2021 had remedial work completed in Aug./Sept. 2020. However, re-assessment for remnant life is yet to be updated.

It is noted that most of the Pipeline Systems were subjected for fitness-for-service (FFS) assessment in 2016. It is understood that the assessment exercise was ALL subjected to results of ILI (In Line Inspection) and not revisited once results of other inspection obtained, i.e. Topside Inspection and Underwater Inspection. The outcome of the assessments were not revisited and the remnant life re-calibrated although there might be findings from the performed subsequent inspections, i.e. underwater inspection and topside inspection. To conclude, the stated remnant life of the Pipeline Systems is not of high confidence.

NO.	PIPELINE ID	Product Description	SERVICE	LATEST IP	LATEST ROV/SSS	LATEST FFS		Threats for High PoF	Mitigation Plan / Remarks
						YEAR	REMNANT LIFE (Year)		
1	BKABKC10PL	FWS Process Liquid	Trunkline	2015	2014	2016	2023	1) Remnant life based on Internal Corrosion Rate (ICR) BKA expansion spool 2) Pipeline threat is Top of Line Corrosion	1) Primary mitigation are in-placed by spray pigging the line bi-weekly. 2) Considering expansion spool replacement / repair with insulation on the next diving campaign
2	BKCBSA20PL	FWS Process Liquid	Trunkline	2016	2014	2016	2022	1) Remnant life based on ICR at BSABKC subsea pipeline, approx 5.1km from BSA platform 2) Pipeline threat is Top of Line Corrosion	1) Primary mitigation are in-placed by spray pigging the line bi-weekly 2) IP planned in 2021 will determine requirement of insulation. 3) Considering expansion spool replacement / repair with insulation on the next diving campaign
3	BSABRB20PL	FWS Process Liquid	Trunkline	2014	2014	2016	2034	Remnant life 20 years based on 2014 IP no Internal Corr growth reported	
4	BTABRC14PL	FWS Process Liquid	Trunkline	2016	2014	2016	2023	1) Remnant life based on Internal Corrosion Rate (ICR) BRC expansion spool 2) Pipeline threat is Top of Line Corrosion	1) IP completed in Sept 2020, awaiting final result 2) Considering expansion spool repair with installation of insulation cover on the next diving campaign subject to IP 2020 result.
5	BRCBRD14PL	FWS Process Liquid	Trunkline	2016	2014	2016	2036	Remnant life > 20 years. No internal corrosion at Subsea pipeline	
6	BKCBRB22PG	FWS Process Gas	Trunkline	2015	2014	2015	2055	Remnant life based on ICR 1st 6km BKC-BSA subsea pipeline.	
7	BRBBKC10WI	Water Injection	Trunkline	2010	2014	2016	2029	Remnant life based on ICR and 2010 IP	1) Operational pigging - monthly 2) IP planned in July 2020 however MFL run been suspended due to poor Caliper run result. MFL tool enhancement required based on Caliper tool result findings
8	BRBBKA4GL	Gas Lift	Trunkline	2014	2014	2016	2023	1) Remnant life based on ICR at BSABKC subsea pipeline, approx 5.1km from BSA platform 2) Risk of 3rd party damage.	IP inspection completed in Sept 2020, awaiting final result

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Table 10.14: Current Issues – Pipelines (1)

NO.	PIPELINE ID	Product Description	SERVICE	LATEST IP	LATEST ROV/SSS	LATEST FFS		REMARKS / Threats for High PoF	Mitigation Plan
						YEAR	REMNANT LIFE (Year)		
9	BRDBRC6WI	Water Injection	Trunkline	2010	2014	2016	2027	13 spans were recorded during the inspection, 1 span exceeding the allowable length.	
10	BRCBTA6WI	Water Injection	Trunkline	2016	2014	2016	2036	Remaining life> 20 years. Pipeline is located in shipping activity area, mainly consists of fishing activity	
11	BRDBRC4GL	Gas Lift	Trunkline	2015	2014	2016	2021	Remaining life based on ECR at BRD subsea riser – under clamp	Repair planned in 2020 Diving Campaign by removing existing clamp and installation of retrofit clamp. Corroded area to be inspected and corrosion coating to be applied – COMPLETED during Aug/Sept SD
12	BRCBTA4GL	Gas Lift	Trunkline	2015	2014	2015	2032	Several dents, areas of pipeline displacements, anchors & a minor 'kink' and have been reported by the 2014 ROV report and the 2015 ILI	
13	BRBFSO10EC	Export Crude to FSO	Export Crude	2016	2014	2016	2036	Remaining life> 20 years. No internal corr reported from 2016 IP	
14	BRBFSO6FG	Fuel Gas to FSO	Fuel Gas	2016	2014	2016	2036	Remaining life> 20 years. No internal corr reported from 2016 IP.	

Table 10.15: Current Issues – Pipelines (2)

NO.	PIPELINE ID	Product Description	SERVICE	LATEST IP	LATEST ROV/SSS	LATEST FFS		REMARKS / Threats for High PoF	Mitigation Plan
						YEAR	REMNANT LIFE (Year)		
1	BOCBOD12PL	FWS Process Liquid	Trunkline	2016	2014	2017	2036	Based on 2016 and 2010 IP Comparison ICR	
2	BOBBOD18PL	FWS Process Liquid	Trunkline	2012	2014	2016	2028	Based on 2018 IP & ROV campaign	
3	BOCBOD24/26PG	FWS Process Gas	Trunkline	2015	2014	2017	2033	Based on ICR, 2018 IP result	
4	BODBOC4GL	Gas Lift	Trunkline	2013	2014	2016	2050	No CWC and piggyback pipeline, risk of anchor drag	
5	BODBOB6GI	Gas Lift	Trunkline	2014	2014	2016	2035	No CWC and piggyback pipeline, risk of anchor drag	
6	BODBRE24EG	Export Gas to BRE	Interfield	2015	2014	2015	2065	ICR from comparison of 2015 & 2010 IP	
7	BODFSO10EC	Export Crude to FSO	Export Crude	2016	2014	2016	2027	ICR 2018 IP - new internal corrosion, may due to previous IP detection capability	IP done in July 2018
8	BODFSO4FG	Fuel Gas to FSO	Fuel Gas	2012	2014	2016	2026	Remaining Life based on ICR (2012 IP), RBI risk based on 2020 IP preliminary findings	IP inspection done end June 2020. Highest WL 54% located at restricted area at FSO riser, inspection verification on-going and rectification work in planning
9	BPABOD24PG	FWS Process Gas	Trunkline	-	-	-	-	Expected TOL Corrosion concern	Completed in Sept 2020, awaiting final result

Table 10.16: Current Issues – Pipelines (3)

Based on the assessed remnant life above, eight (08) Pipeline Systems in PM3 would have their remnant life end earlier than the expiry of the PSC. The design life of these Pipelines is also expected to end earlier than the expiry of the PSC. For information, there is no details of Pipeline System design years readily available. However, design life of 20 years is inferred from the design life of the associated Jackets structures. The Pipelines of concern are as follow:

- BKABKC10PL
- BKCBSA20PL
- BTABRC14PL
- BRBBKA4GL (3Systems)
- BRDBRC4GL
- BODFSO4FG

Following this, a further 12 pipelines may require attention within 10 years of PSC extension. And finally, three (03) pipelines are expected with assessed remnant life exceeding the project end of economic field life in 2043.

Full well stream process gas pipeline BKCBRB22PG is assessed with remnant life of until 2055, based on a survey BKS-BSC section. This could be optimistic considering the corrosive nature of PM3 produced fluids and other pipeline data. There is no potential concern until late field life. However further evaluation will be required.

Gas lift pipeline BODBOC4GL is assessed with remnant life of until 2050, based on dry gas operation. Due to the low corrosive nature of conveyed fluids, internal corrosion is not a potential threat until late field life. However, further evaluation will be required.

The pipeline transporting dry gas from PM3 North to PM3 South, BODBRE25EG, is assessed with remnant life of until 2065. However, it could not be confirmed if the assessment had taken into consideration of a wall loss corrosion anomaly of 35% located at log-distance 35,856m (subsea). This location will need to be closely monitored. This is a routine maintenance expense.

BKABKC10PL Pipeline has suffered an external corrosion at its riser splash-zone. This has since been addressed by temporary repair in 2020. Permanent repair is planned for 2021 (check WP&B). There is also an internal corrosion anomaly at its subsea section which may require sectional replacement.

BKCBSA20PL Pipeline is planned for expansion spool replacement by 2022. The Pipeline is also to have suffered wall loss up to 64.1% due to external corrosion, located at BKC export riser (under I-Tube). The remedial work for this is planned in 2021. However, based on 2021 WP&B, there is no funds seem to have been budgeted for works.

BTABRC14PL Pipeline has previously suffered a failure due to perforated wall along its riser at BTA-end in Sept. 2016. The perforated section was subsequently addressed by flanged-connection sectional replacement in 2017. The recent IP performed in Aug. 2020, identified an external corrosion defect with thinnest remaining wall thickness of 7.52mm, equivalent to 60.5% wall loss based on its nominal wall thickness of 19.05mm. The Pipeline was installed in 2006 and the degradation that this defect suffered is at 0.83mm/yr, which is critically high. The thinnest measured pipe wall due internal wall loss corrosion anomaly 9.37mm, equivalent to 46.4% wall loss, based on its nominal wall thickness of 17.05mm. The exact locations of the defects are not readily available. However, remedial work and improvement plan in corrosion control will need to be established for the external and internal corrosion anomaly respectively.

BRBBKA4GL Pipelines have suffered mechanical damage and displaced due to anchor drag. The remedial work by placement of concrete mattress has been deferred to 2022. In addition, there are concerns pertinent to external corrosion under I-tube and internal corrosion at the subsea section. The recent IP performed in Sept. 2020, identified thinnest pipe wall section of 2.57mm due to external corrosion, equivalent to 64.1% wall loss, based on nominal wall thickness of 7.14mm. The exact location of this defect is not readily available. However, remediation work will need to be planned accordingly. The current condition of the previously reported corrosion under I-tube could not be assessed due to limited information received.

BRDBRC4GL Pipeline had its corrosion under riser clamp repaired in 2020. The pipeline remnant life requires review revision following this repair.

The remaining 12 pipelines with remnant life with remnant life less 10 years after PSC expiry (2037), 1 water injection pipeline remnant is 2027 with the remainder having remnant life 2032 to 2036. With limited data available it has not been possible to evaluate potential concerns or remedial actions. However, due to the nature of the produced fluids, a conservative assumption of 3 subsea sectional replacements between 2027 and 2037 and further 3 to end of projected economic field life of in 2043 is included in section 11.3.

Top of line corrosion is a common feature in PM3 due to wet high CO_2 fluids. Effective corrosion management programme would prolong the operational life of the Pipeline Systems. Compliance with chemical treatment and operational pigging is critical to ensuring no unexpected pipeline failures during operation.

Kinabalu pipelines remnant life exceeds the PSC expiry of Dec 2032. However, remedial action to address topsides section external corrosion for PL_311A and free spans on both pipelines (PL_311A and PL_312) may be required if not completed prior to asset handover. The underwater inspection planned in 2020 to monitor free spans is now scheduled for 2021.

10.4.4 Pipeline Concerns

There is a notable quantity of integrity concerns for the Pipeline Systems. The main concern is presence of internal and/or external wall loss anomalies along the sealine section of the Pipelines. These anomalies are regarded as of such due the complication and cost associated with its remediation work, i.e., subsea intervention. The next integrity concern of a lesser degree relatively is presence of critical free spans. These spans have exceeded the design maximum allowable span length and susceptible to fatigue failure due to vortex induced vibration.

It is also to be noted that four (04) of the Pipelines have suffered some form of mechanical damage due to anchor drag. The Pipelines are gas lift lines which normally operate at high pressure. Based on the outcome of the 2020 UWI remediation of concrete mattress placement is planned for 2022.

BODFSO4FG pipeline provides fuel gas to FSO Orkid. The recent IP performed in June 2020, identified thinnest pipe wall section of 2.62mm due to external corrosion, equivalent to 56.5% wall loss, based on nominal wall thickness of 6.02mm. The defect is approximated to be located along the vertical pipe between flange and pipe support at the FSO riser. The defect is not of an immediate threat to the integrity of the system. However, remedial works will need to be planned and executed during the next available opportunity.

BTABRC14PL Recent 2020 IP data indicates up to 60.5% wall loss due to external corrosion and six (6) internal metal loss anomalies with greater than 15% metal loss. These anomalies are of immediate threat. However, remedial works will need to be planned and executed during the next available opportunity.

BRBBKA4GL Pipeline provides gas lift to BSA, BKC and BKA wellheads with 5 riser sections and 3 subsea seabed sections over a total length of 15,288m. Recent 2020 IP data 64.1% wall loss with a minimum wall thickness of 2.57mm. Remedial works will need to be planned and executed, probably by riser replacement and/or subsea sectional replacement for its continuous technical integrity till the end of PSC.

BPABOD24PG Pipeline System was installed in 2018 and has just had its baseline IP completed in Aug. 2020. Almost the entire subsea section of the Pipeline was found to have suffered wall loss due to Top-of-Line (ToL) corrosion. The highest wall loss recorded was 49% at its sealine section, at km 3.069. It is a major concern as the pipeline is suffering a serious extent of internal degradation despite having been in operation for only 2 years and also with internal corrosion preventive maintenance activities. The concern has been noted and improved remediation activities are in plan.

Other concerns are mainly associated with wall loss due to internal or external corrosion at topside / riser atmospheric section. These concerns can be suitably addressed by either sectional replacement, engineered wraps or mechanical cleaning and painting, depending to the extent of wall loss.

10.4.5 Pipeline Way Forward

Most of the Pipeline Systems are still within an acceptable level of integrity, based on the assessed remnant life and planned remedial work. The Pipelines were mostly installed in 2003, 2005 and 2008 with design life of 20 years, inferred from the design life of the associated offshore installations.

As the way forward, the readily identified technical concerns will all need to be first addressed and their integrity reinstated. Subsequently, further degradations or damage mechanisms will need to be reduced to lowest rate possible. This may require an implementation of a robust Pipeline Integrity Management Strategy (PIMS).

On assumption of operator ship SEAH would conduct a complete review of available pipeline surveys and IP data to validate the pipeline remnant life, refine operational and IP pigging strategy and formulate a pipeline remedial action plan where required. At this time estimated cost of pipeline remedial action based on the VDR information is included is section 9 of this report.

10.5 FSO Integrity

PM3 CAA includes two turret moored ex-trading tankers operating as floating storage and offloading (FSO) vessels. The vessels were selected and converted for use during the development projects for Bunga Raya (FSO PM3 CAA) and Bunga Orkid (FSO Orkid).

Oil is transferred from the processing platform via a fixed pipeline, pipeline end manifold (PLEM) and flexible riser into the tanker's cargo tanks. The FSO's store and condition the oil while building a cargo volume for offload to visiting takers via fiscal standard oil meters and floating hose. Fuel gas is also supplied to the FSO via dedicated fixed pipeline, pipeline end manifold and flexible riser.

FSO PM3 CAA is owned by the PM3 CAA PSC but operated and maintained under contact by FPSO Tech. FSO Orkid is owned and operated by MVOT and leased by PM3 CAA.

The FSO operator is responsible to maintain the vessel to recognised Class which includes regular independent inspection the Classification Society.

10.5.1 FSO PM3 CAA (PM3 South)

FSO PM3 CAA is owned by PM3 CAA and register in Panama as an FSO. FPSO Tech DN. BHD were contracted to design, engineer, construct, convert, install, operate and maintain the vessel. The operating and maintain contract period is for a period of 20 years from provisional delivery date 17 September 2003 to 18 September 2023.

The vessel was constructed in 1989 by Mitsubishi Heavy Ind. Ltd. as a single hull Aframax oil trading tanker. It was converted to an FSO in 2001 – 2003 and extend for an additional 100kbbl storage capacity giving overall capacity of 850kbbbl including storage and slops tanks.

FSO PM3 CAA has a class notification of A1, Floating Storage and Offloading System. The most recent survey report by American Bureau of Shipping (ABS), the classification society, was issued on 6 January 2021 with no vessel findings or overdue surveys.

There is one open comment from the Special Continuous Survey – Hull 5 dated 20 March 2021: *Found smooth indentation/set in of approximate length of 1000mm x 500mm width x approximately 25mm depth at vessel hull starboard side, forward of frame (in way of Cargo Tank No 1 stbd) and 7800mm from freeboard deck.* With no more recent entries it is assumed there has been no noticeable deterioration. The next Special Continuous Survey – Hull 7 is due 31 Jan 2024.

No information was available on the condition of PLEM, FSO mooring system or floating loading hose.

10.5.2 FSO Orkid (PM3 North)

Malaysia Vietnam Offshore Terminal Limited own and operate FSO Orkid and provide the vessel to Repsol for operation in PM3 North on a Supply, Operate and Maintain contact until 31 Dec 2027. The vessel is registered in Port Kelang, Malaysia as an Offshore Service Vessel.

The vessel was constructed by Onomichi Dockyard Co. Ltd. in 1989 as a single hull Aframax trading tanker with overall capacity of 750kbbbl including storage and slops tanks. It was converted to an FSO in 2008.

FSO Orchid has a class notation of Offshore Service Barge Oil Storage. The last survey by Bureau Veritas, the classification society, is dated 22 September 2020. There are no overdue surveys noted but one Class Item due 28 February 2021: *Definitive repairs to be carried out at wasted and thinning down main deck butterworth hole ring for No 5S WBT and further assessment be carried out during next scheduled annual survey.*

The next Bottom Survey in Dry Dock or Afloat is due 5 Jul 2022.

No information was available on the condition of PLEM, FSO mooring system or floating loading hose.

10.6 Maintenance and Inspection Strategy and Implementation

10.6.1 Maintenance Strategy

The Repsol maintenance strategy is based on equipment on criticality rating and assigned a preventative maintenance plan based on criticality and equipment type (Figure 10.6). This is a typical approach in the oil and gas industry. Equipment criticality is based on safety or process function and preventative maintenance is generally based on industry practice and/or local operational experience.

Across all facilities assets there 52209 equipment tags which are group into 2523 equipment groups in the Repsol maintenance management system. PM3 South accounts for the largest proportion of equipmnet with the BRA, BRD and BRE housing separation, compression and CO2 removal plant.

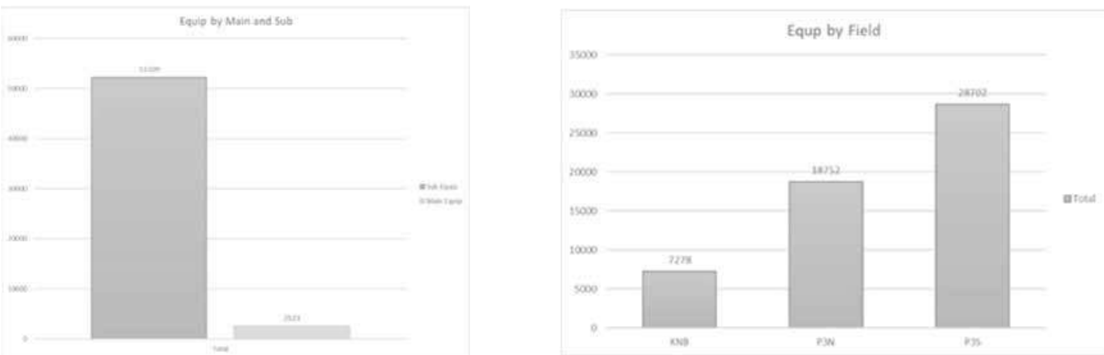

Figure 10.6: Equipment Maintenance

Equipment is classified into workcenters five with instrumentation the largest by equipment count (Figure 10.7).

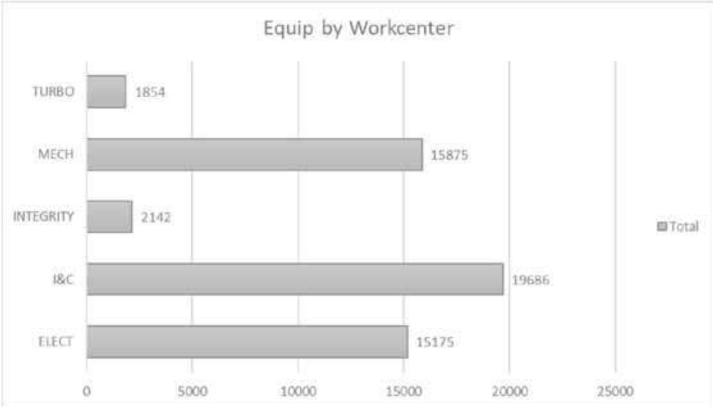

Figure 10.7: Equipment Workcentres

Of the 2523 maintainable groups 1285 categorised safety criticality, 424 production critical and 812 non-critical equipment. All safety and production critical equipment and 535 non-critical equipment have preventative maintenance plans, leaving 277 non-critical equipment with no preventative maintenance plan.

No information was made available on specific equipment maintenance strategies, however major rotating equipment is maintained on a basis of run hours complemented condition monitoring. It is noted that maintenance is conducted by both Repsol maintenance crew and by third party service providers. Field Service Representative (FSR) support contracts are in place with Siemens and Solar for Major Machinery Overhauls (MMO) and predictive maintenance monitoring. A specialist crane contractor provides maintenance and inspection services. In addition, Repsol utilise original equipment manufacturers for parts supply and servicing of major pumps and other key equipment.

Repsol maintenance strategy includes an annual turnaround (planned shutdown) to enable vessel inspection, planned maintenance and repairs which require plant shutdown and hydrocarbon free. PM3 annual turnaround alternates between 14 and 7+2(start-up) days. Kinabalu annual turnaround is scheduled for 1+3(start-up) and 10+3(start-up) alternate years.

10.6.2 Maintenance Implementation

Maintenace compliance has normally been very good with minimum backlog, however from early 2019 throught to mid-2020 there has been a significant increase in all planned and corrective maintenace which includes safety critical equipment. The graphs below summarise compliance with planned maintenance (PM) and corrective maintenance from January 2019 to August 2020.

Repsol explained the backlog was in large part due to changing the Computerised Maintenance Management system from Maximo to SAP creating a backlog in signed off completed work. Training and improvements to CMMS workflows has reduced the backlog significantly by the end of 2020. Covid-19 movement restrictions also contributed to the backlog through delays in mobilising vendors and campaign workforce.

10.6.2.1 PM3 Maintenance Implementation

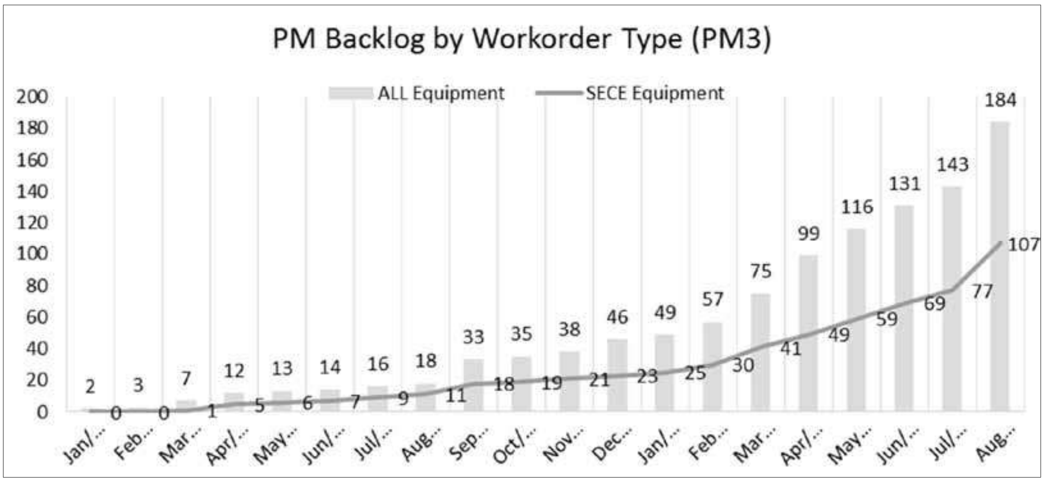

Figure 10.8: PM Backlog by Workorder Type (PM3)

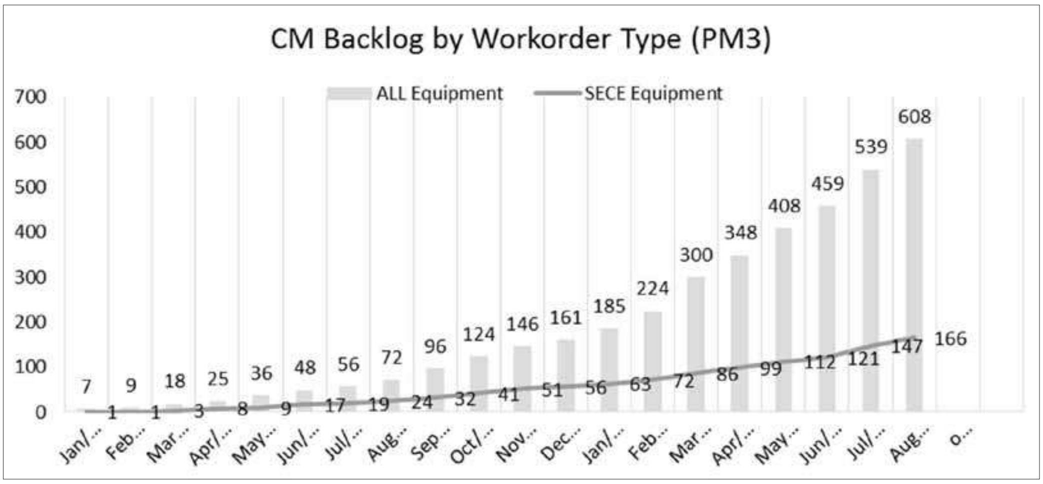

Figure 10.9: CM Backlog by Workorder Type (PM3)

PM3 Safety Critical Elements Inspection & Maintenance Program Status			
Safety Critical Elements	**Year End 2019 % Completion v Planned**	**June 2020 % Completion v Planned**	
Lifesaving	99.74	99	
Emergency Response	96.58	92	
Shutdown System	98.80	50	ESD Test scheduled for planned shutdown
Detection System	100	100	
Protection System	96.62	98	PM3S FWP performance test pending PM3N FWP A onshore overhaul & 6 M PM pending
Ignition System	87.32	86	Ex inspection
Process Containment	98.86	94	

Table 10.17: PM3 Safety Critical Elements Inspection & Maintenance Program Status

In addition to the increase in backlog some maintenance activities were deferred or scope reduced in 2020 due to the economic and logistics impact of Covid-19. This is reflected reduced Opex for 2020 and subsequent the rise in forward years.

10.6.2.2 Kinabalu Maintenance Implementation

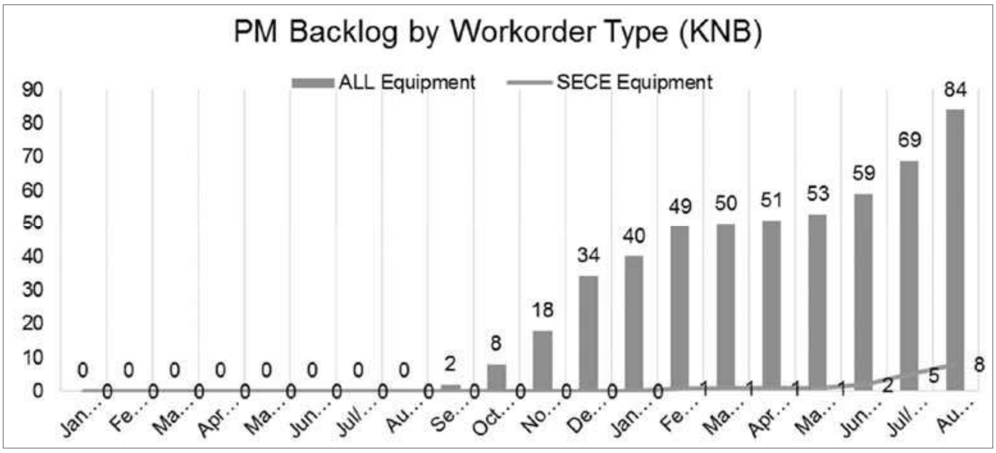

Figure 10.10: PM Backlog by Workorder Type (KNB)

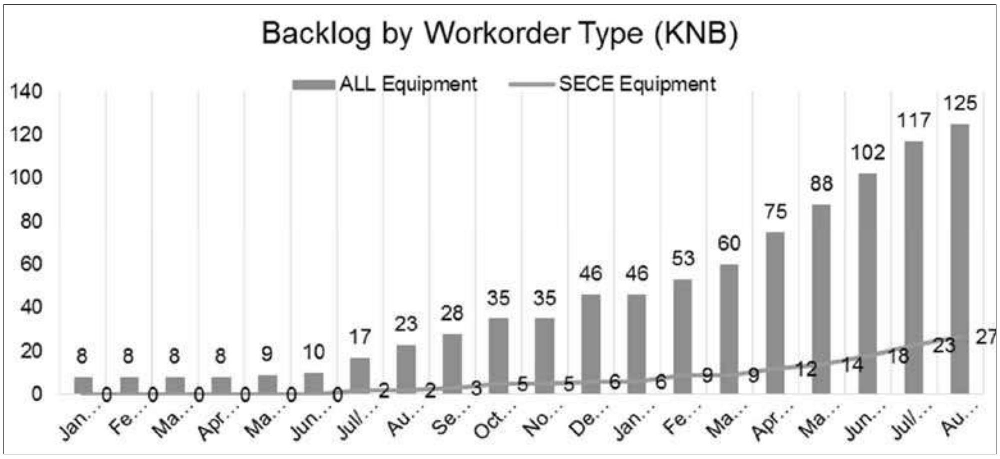

Figure 10.11: Backlog by Workorder Type (KNB)

Kinabalu Safety Critical Elements Inspection & Maintenance Program Status			
Safety Critical Elements	**Year End 2019 % Completion v Planned**	**Sept 2020 % Completion v Planned**	
Lifesaving	100	91	
Emergency Response	100	94	
Shutdown System	100	94	
Detection System	100	97	
Protection System	100	91	
Ignition System	100	80	Hazardous Area inspection
Process Containment	99	83	LP Comp & Diesel Tank inspection

Table 10.18: Kinabalu Safety Critical Elements Inspection & Maintenance Program Status

In addition to the increase in backlog some maintenance activities have been deferred or scope reduced in 2020 due to the economic and logistics impact of Covid-19. This is reflected reduced Opex for 2020 and subsequent the rise in forward years.

10.6.2.3 Maintenance Costs

Repsol has made significant reductions in maintenance costs over the 5 years period from 2015 to 2019. PM3 CAA maintenance costs are reported to have reduced by half. Excluding 2016, Kinabalu maintenance cost reduction over the same 5 years period is 25% (Figure 10.12).

Figure 10.12: PM3 CAA & Kinabalu Maintenance Costs

Repsol explained the cost reduction are the result of reviewing maintenance strategies, working with equipment manufactures to optimise schedule and scope of planned maintenance and overhauls and improving efficiency of maintenance delivery. In market condition in 2016 following rapid drop in oil price could have also contributed to cost savings. The levelling off in 2018 and 2019 suggests major cost reduction initiatives have been delivered and these figures could be considered the normal level for present maintenance strategy and market conditions.

10.6.3 Inspection Strategy

Repsol inspection strategy practices are based on the outcomes of hazard identification risk assessment. A risk value is assigned for each possible threat identified based on its likelihood and consequence. Once the risk level determined, an appropriate method of inspection, survey, monitoring and testing with respective frequency are identified. This information is then translated into Risk-Based inspection programme. The current programme of 5-year risk-based inspection programme of between 2021 and 2025 is readily in place. Based on this programme, a detailed annual inspection plan is developed.

- Topside Inspection (Pipeline)
- Topside Structural Inspection
- Fabric Maintenance Program
- Insulation Inspection and Reinstatement
- Underwater Inspection (Pipeline & Jacket)
- Chemical Treatment Program
- Operational and Intelligent Pigging
- Process Piping Inspection
- Pressure Vessel Inspection

Details of work scopes and schedules to address structural or pipeline were not readily available.

Repsol is in the process of migrating integrity and inspection into SAP. At present anomalies are tracked on a separate list and managed by a dedicate Engineer. Once the migration is complete anomalies will be managed via SAP.

Repsol provided a copy of the 2020 integrity risk assessment for PM3 and Kinabalu.

PM3 South risk matrix below (Figure 10.13) identifies 7 significant asset integrity risks (2 pipeline, 3 topsides pipework, and 2 structural).

PM3S Risk Matrix

REPSOL

	Issue/Risk	Description/Mitigation	Spend (USD Million) 20	21	22	23
1	Corrosion Under Insulation (CUI) lead to LOPC	Remove insulation for inspection & fabric maintenance and replace personal protection from rockwool to cage type	0.2	0.24	0.24	0.24
2	External Corrosion including Corrosion Under Pipe Support lead to LOPC	Continue progress with fabric maintenance and spool replacement	2.0	2.6[4]	0.9	0.45
3	Sand erosion on flowline and jumper line	Continue thickness monitoring based on information provided by Sand Management Team	0.15	0.17	0.18	0.19
4	Top of the line (TOL) Corrosion for pipeline	Continue with maintenance pigging, conduct Intelligent Pigging (IP) and install insulation cover on the pipeline	0.31	2.9[3]	0.2	0.2
5	4GLs displaced pipeline (BSABKC4GL, BRDBRC4GL, BRCBTA4GL and BKCBKA4GL)	Displaced 4GLs pipeline due to anchor drag. To plan for concrete mattress placement to mitigate the displacement issue. ROV campaign to revisit and observe the condition in 2020	1.1	0.24	-	-
6	BRD hull tilting due to leak on 3 topside legs	Risk Reassessment for safe continuous operation has been conducted. Temporary online monitoring will be installed in Q4, 2020.	0.5[1]	0.5[2]	0.1	0.1
7	BKA Jacket Fatigue issue	The fatigue analysis by 2016 DnV reported result with twenty-two (22) brace-chord connections with less than 20 years fatigue life with safety factor of 2.0 (using a new metaocean data) In 2018, a ROV campaign has been executed to reinspect the anomaly findings that was found in 2010 and reclassified the anomaly as non-integrity threat. Asset Life Extension Study is currently on-going where metaocean data will be cross-checked with other Operators in the region and Ultimate limit state (pushover) analysis will be conducted.	0.13	-	-	-

Note:
1 Include ROV inspection, ALE and RBI Reassessment
2 ACFM inspection and Leg Repair
3 Include purchase and installation of Insulation Cover
4 Include dedicated temporary LQ for the campaign

/2020

Figure 10.13: PM3 South Risk Matrix

Pipeline top of line corrosion was evaluated as a high integrity risk confirming the criticality of compliance with pipeline maintenance and inspection program and the need for sectional replacements to some pipelines. The mitigation costs are not sufficient enough to include pipeline sectional replacement. In addition, pipeline drag is evaluated as a medium-high risk with mitigation to install concrete mattresses.

Topsides pipework has two medium-high risks, corrosion under insulation and corrosion under supports. Mitigation of both these issues are included in inspection and repair campaigns in 2002 and 2021. Sand erosion of flowlines and jumpers it evaluated as a medium risk with ongoing monitoring as mitigation. Delivery of the pipework inspection, repair and painting programs is critical in identification, managing and reducing these risks.

BRD hull tilting and BKA jacket fatigue and are identified as medium-high and medium risks respectively with critical outcomes but very low probability. Mitigation for BRD is to install shims and complete structural studies to assets long-term structure integrity. BKA Asset Life Extension structural studies are in progress to assess the jacket fatigue life.

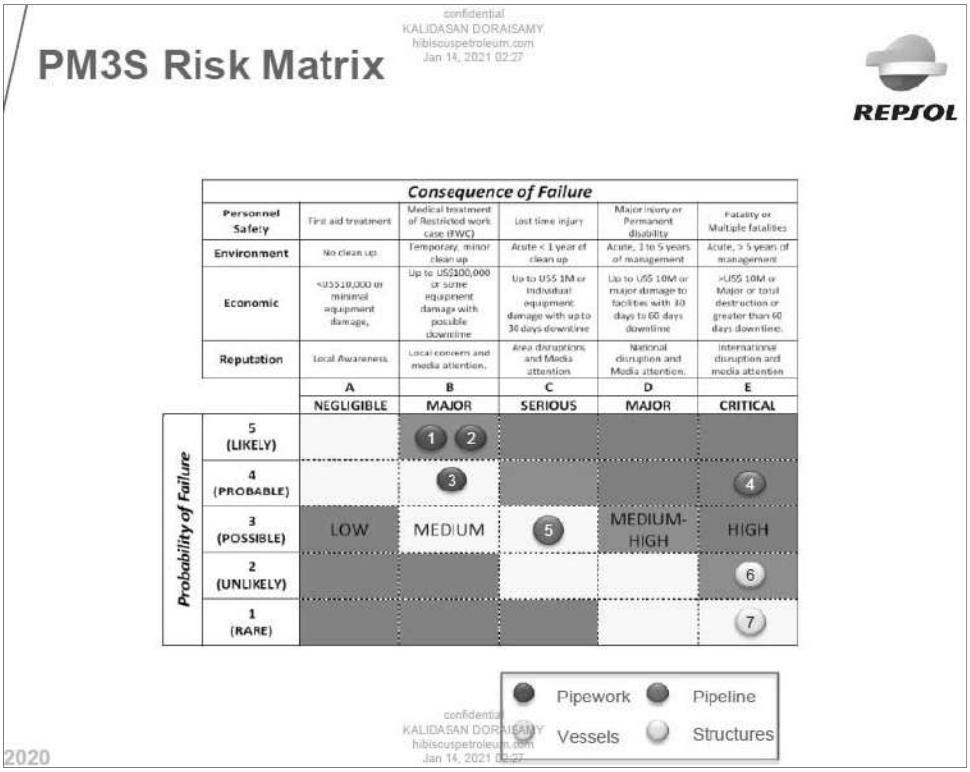

Figure 10.14: PM3 South Risk Matrix

PM3 North risk matrix below (Figure 10.15) identifies 7 significant asset integrity risks (2 pipeline, 3 topsides pipework, and 2 structural) most of which are the same as PM3 South.

PM3N Risk Matrix

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REPSOL

			Spend (USD Million)			
	Issue/Risk	**Description/Mitigation**	**20**	**21**	**22**	**23**
1	Corrosion Under Insulation (CUI) lead to LOPC	Remove insulation for inspection & fabric maintenance and replace personal protection from rockwool to cage type	0.1	0.2	0.2	-
2	External Corrosion including Corrosion Under Pipe Support lead to LOPC	Continue progress with fabric maintenance and spool replacement	0.95	0.75	0.38	0.38
3	Sand erosion on flowline and jumper line	Continue thickness monitoring based on information provided by Sand Management Team	0.2	0.22	0.24	0.26
4	Top of the line (TOL) Corrosion for pipeline	Continue with maintenance pigging, conduct Intelligent Pigging (IP). Pipeline has been replaced in 2015	1.04	0.2	0.59	0.59
5	Span issue at BODBOB6GI at KP 1.563 to KP1.577	Plan to rectify the situation during 2021 Diving campaign	-	0.24	-	-
6	Scour issue at BOA (5 piles)	First observation in 2010 and after 3 observations, the scour area were progressing and nearing the design limit. Plan to rectify the situation using cement bag during Diving campaign in 2021	-	0.24	-	-
7	Depleted anodes for PM3N Jacket	CP reading and analysis are planned during 2020 ROV campaign. Rectification plan depends on the finding	0.2	-	-	-

Figure 10.15: PM3 North Risk Matrix

Pipeline top of line corrosion was evaluated as a high integrity risk confirming the criticality of compliance with pipeline maintenance and inspection program in PM3 North. The mitigation costs are not sufficient to include pipeline sectional replacement. In addition, pipeline free spans are evaluated as a medium-high risk with mitigation to install sandbags in 2021.

As with PM3 South topsides pipework has two medium-high risks, corrosion under insulation and corrosion under supports. Mitigation of both these issues are included in inspection and repair campaigns in 2002 and 2021. Sand erosion of flowlines and jumpers it evaluated as a medium risk with ongoing monitoring as mitigation. Delivery of the pipework inspection, repair and painting programs is critical in identification, managing and reducing these risks.

PM3 North structural risks are identified as scouring at BOA and jacket anode depletion. Both are identified as medium risks respectively with serious outcomes but very low probability. Mitigation for BOA souring to install cement bags was planned for 2021. With ROV survey in 2020 planned to evaluate severity of anode depletion to inform remedial action.

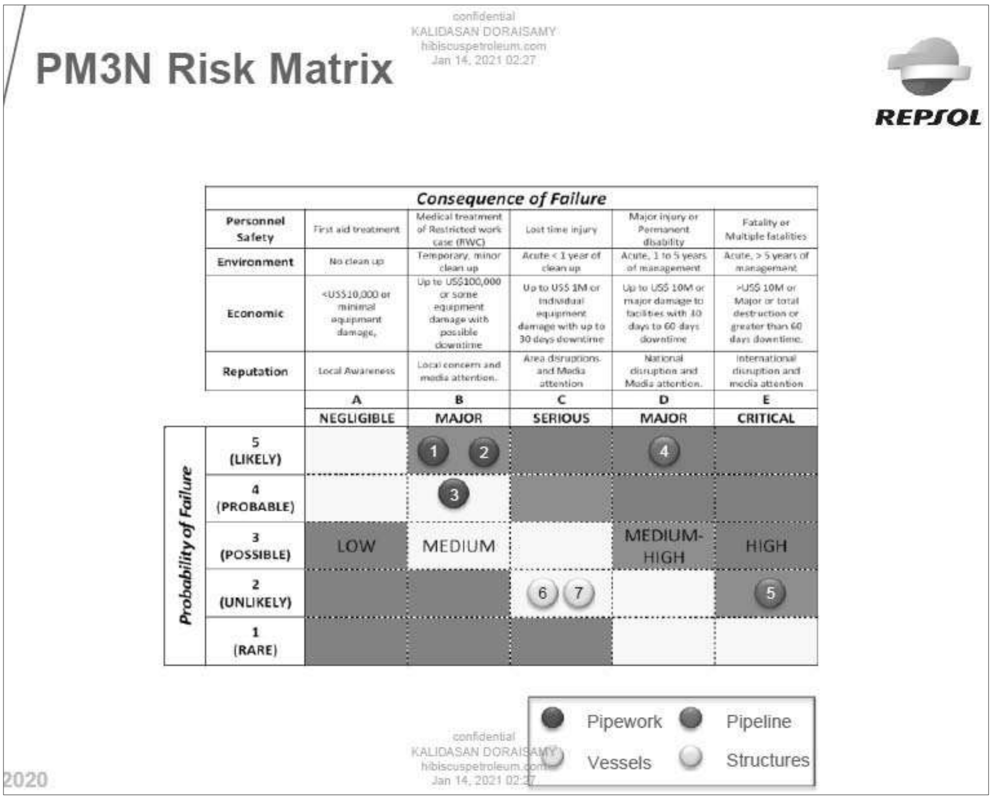

Figure 10.16: PM3 North Risk Matrix

Kinabalu integrity risk matrix identified one (1) pipeline and three (3) topsides pipework significant risks (Figure 10.17).

KNB Risk Matrix

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REPSOL

	Issue/Risk	Description/Mitigation	Spend (USD Million)			
			20	21	22	23
1	External Corrosion including Corrosion Under Pipe Support lead to LOPC	Plan for fabric maintenance and spool replacement	0.04	0.3	0.3	0.15
2	Vibration Fatigue lead to LOPC	To conduct vibration monitoring and consider improving HP Compressor's design to reduce vibration	0.1	0.1	-	0.1
3	Sand erosion on flowline	Continue thickness monitoring based on information provided by Sand Management Team	0.12	0.14	0.16	0.18
4	Localized Corrosion due to presence of SRB	Continue with maintenance pigging, conduct Intelligent Pigging (IP) and install insulation cover on the pipeline	0.5	0.2	0.03	0.03

Figure 10.17: KNB Risk Matrix

Pipeline internal corrosion due to SRB's is recognised as a high risk with maintenance and IP pigging recommended as mitigation. Subsequent discussions with Repsol clarified the application of biocide to pipeline fluids has been introduced to control SRB growth.

Topsides pipework corrosion under supports and vibration fatigue due to HP compressor are evaluated as major. A campaign to address corrosion under supports is recommended as per PM3. In 2020 Kinabalu experienced and number of gas releases due to fatigue cracking of HP compressor components and pipework.

Sand erosion of flowlines and jumpers is evaluated as a medium risk with ongoing monitoring as mitigation. Delivery of the pipework inspection, repair and painting programs is critical in identification, managing and reducing these risks.

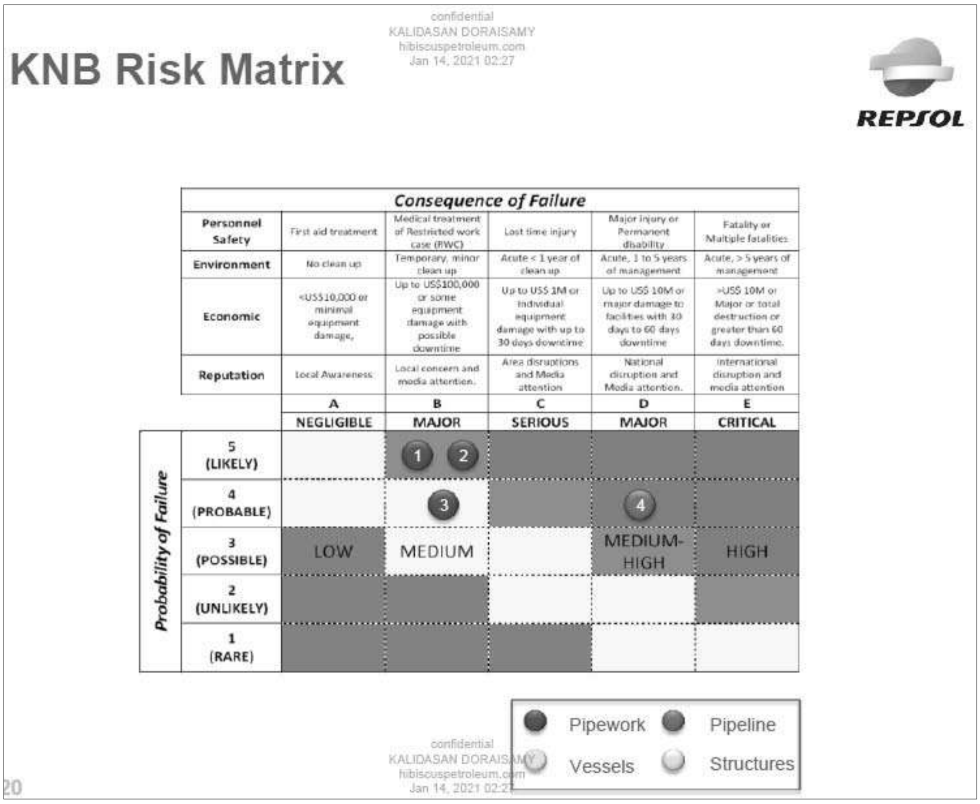


Figure 10.18: KNB Risk Matrix

The risk matrixes above are consistent with other information available in the VDR and indicate Repsol's application of risk management to asset integrity. Implementation of mitigation plans, ongoing inspection and review of asset integrity are key to successful management of asset integrity risk. With the assets being divested and recent drop in oil price there is potential for deferment of high-cost mitigation work by the operator.

10.6.4 Inspection Implementation

Inspection activity is an element of effective integrity management program. Repsol executes inspection tasks as part of their integrity management strategy to ensure that the required integrity levels of their Assets are being maintained. Inspection tasks are performed at defined regular intervals in accordance with IMS inspection plan. The inspection frequencies are chosen based on risk assessment, experience and engineering judgement. Sometimes, additional inspections are performed in response to an incident if a possible integrity threat is indicated.

10.6.4.1 PM3 Inspection Implementation

According to data presented in IOM packs, compliance of inspection works in 2019 and 2020 is relatively high (Table 10.19).

	Plan 2019	YE 2019	Plan YTD Sept 2020	YTD Sept 2020	
Topsides	364	364	110	100	2020 CUI scope delay by MCO.
Structural	13	13	14	14	

Table 10.19: PM3 Inspection Plan

In 2020 a total 19 internal vessel inspections (15 PM3 South and 4 PM3 North) were removed from the shutdown plan following RBI re-assessment and replaced with external inspection. The corrosion under insulation inspection scope was also deferred to start October 2020. These changes were caused by logistics challenges and cost reduction drives in response to the Covid-19 pandemic.

10.6.4.2 Kinabalu Inspection Implementation

Similarly, in Kinabalu Asset, the compliance of inspection completion works in 2019 and 2020 is relatively high (Table 10.20).

	2019 Plan	2019 YE	2020 Plan YTD	2020 YTD	
Topsides	40	40	26	21	
Structural	2	2	2	0	Deferred to 2021 due to CMCO restrictions

Table 10.20: Kinabalu Inspection Plan

10.6.5 OSRMS and IOAIA Audits

To comply with the Malaysia Offshore Self-Regulation regulated the Department of Occupational Safety, PETRONAS requires each PSC operator to implement an Offshore Self-Regulation Management System. The aim of the OSRMS is to provide a structured system for all offshore operators to self-manage the integrity of machinery and other equipment in compliance with Malaysian statutory requirements and PETRONAS guidelines.

IOAIA audits perform an important role in evaluate PSC operators OSRMS implementation, effectiveness and propose action to address gaps of introduce improvements. The audit includes documentation review, interviews and physical inspection focusing on the 13 IOAIA Elements as follow:

1) Structural Integrity
2) Process Containment
3) Ignition Control
4) Detection Systems
5) Protection Systems
6) Shutdown Systems
7) Emergency Response
8) Life Saving
9) Hydrocarbon Metering Integrity
10) Rotating Equipment Reliability
11) Electrical Equipment Reliability
12) Wells Integrity
13) Management Assurance

PM3 was audited in 2014 and 2016 with a total of 611 findings as per Q4 2-19 IOM slides. The Kinabalu audit identified 207 findings with all closed as per Q4 2019 IOM slides. None of the audits or close out repots were available in the VDR.

10.7 Operational Efficiency and Availability

Facility availability is a combination of many factors from design, capacity, installed redundancy, individual equipment reliability and maintenance effectiveness. There is no single matric however a combination of operational efficiency and major equipment availability provides an insight into the overall facility availability.

10.7.1 Operational Efficiency 2019 / 1H 2020

Repsol report a score card against KPI's for hydrocarbon liquids production, sales gas, planned deferment and unplanned against agreed in the annual WP&B targets. The set of metrics are a useful guide to overall production performance of an asset.

10.7.1.1 PM3 Operational Efficiency 2019/1H2020

KPI	Unit	Full Year 2019			1H 2020		
		WP&B	Actual	VAR	WP&B	Actual	Var
H/C Liquid (oil & condensate)	Mbopd	23.0	21.5	(1.5)	21.2	19.1	(2.1)
Gas Sales	MMscf/d	257.0	244.3	(12.7)	214.0	214.2	0.2
Planned deferment (H/C liquids)	%	6.0	4.6	1.4	6.8	0.9	5.9
Unplanned deferment (H/C liquids)	%	3.0	6.1	(3.1)	4.0	7.0	(3.0)
Planned deferment (Gas)	%	5.5	5.0	0.5	12.1	0.5	11.6
Unplanned deferment (Gas)	%	3.6	5.0	(1.4)	4.0	5.6	(1.6)
OEE (H/C liquids)	%	97.0	93.9	(3.1)	96.0	93.0	(3.0)
OEE (Gas)	%	96.4	95.0	(1.4)	96.0	94.4	(1.4)

Table 10.21: PM3 Operational Efficiency

OEE an overall operation efficiency calculated as actual H/C liquid production or gas sales less planned deferment as percentage of potential H/C liquid production or sales gas.

2019 full year was below target liquids production and gas sales with higher unplanned deferment slightly offset by lower planned deferment. The most significant contributors to below plan liquids production were loss of condensate yield due to BRE refrigeration compressor shutdown, BSA ESD cascading to BKC & BKA, water out of 5 southern field wells, delays to drilling infill well at BOB and disappointing results of BOC-8ST1 well intervention. Lower gas sales resulted from BOC ESD due to loss process control system power, Resak shutdown no gas sales to Malaysia, back pressure limitation in Ca Mau pipeline to Vietnam and higher water cut in base wells.

The planned maintenance shutdown in 2020 is in the second half (August) thus a lower planned deferment to date, however significantly higher unplanned deferment results in the overall efficiency being below target for both liquids production and gas sales. The main contributors to below plan liquid production are reduced BOA gas lift compressor pressure, BRE refrigeration compressor performance, higher base decline, lower performance from workover wells, lower gas demand resulting lower condensate production. Gas sales was impacted by BRE Memguard switching valve (Zwick Valves) failures reducing BRE capacity, BRE PSD, BRE refrigeration compressor performance, BKC-7 well integrity issue, BOD-8 & 12 well sand production and lower demand from Vietnam (single buyer).

BOA gas lift compressor low pressure was due to reduce cooling capacity of the discharge cooler. This is a plate cooler using demineralised water cooling medium. The cooling medium side of the exchange suffered surface fouling. The medium was changed out and the plates cleaned in October 2020.

Repsol utilises a production loss reporting and root cause analysis to identify and prioritise well and equipment issues responsible for deferred production. Base on the 2020 4Q IOM pack the highest value issues have been resolved or have an action plan in progress including BRE Memguard switching valve failures, BRA Flash Gas Compressor air inlet upgrade and BRD Gas Lift Compressor failure to crank investigation.

10.7.1.2 Kinabalu Operational Efficiency 2019/1H2020

KPI	Unit	Full Year 2019			1H 2020		
		WP&B	Actual	VAR	WP&B	Actual	Var
Oil	Mbopd	14.6	14.9	0.3	17.9	17.4	(0.5)
Planned deferment	%	6.0	5.7	0.3	10.3	1.1	9.2
Unplanned deferment	%	4.7	8.6	(3.9)	4.7	5.8	(1.1)

Table 10.22: Kinabalu Operational Efficiency

2019 full year was slightly above target (Table 10.22). Better than expected performance of new wells early in the year was offset by higher water cut in base wells later in the year, extended maintenance shutdown, HP compressor issues, produced water shutdown and Samarang gas handling issue.

The planned maintenance shutdown in 2020 is in the second half (September) thus a lower planned deferment to date. Unplanned deferment is above plan with the main contributors being flare constraints due to HP and LP compressor trips, power failure, produced water issues and Samarang reduced gas take.

The process is constrained by liquid capacity and gas capacity. Flare limitations required wells to be cut back on loss of gas export to Samarang. Loss or reduction in produced water handling also results in shutting in wells to optimise oil production.

The HP compressor has low reliability caused by high vibration including cracked pipework and pulsation dampeners. A gas capacity debottlenecking project will include addressing the vibration issues however this project is under review with no planned implementation date.

10.7.2 Major Equipment Availability

The following provides availability details of the individual facilities as presented in the IOM and AMIR reports.

10.7.2.1 PM3 Major Equipment Availability

PM3 major equipment availability in 2019 and 2020 is good (Table 10.23). This is a result of high individual unit availability and installed spare capacity for critical power generation, and gas compression duties.

PM3 maintenance contract with Solar includes preferential engine replacement on early failure. This reduces time to repair/replace on unexpected early failures.

	Gas Lift Compression	Export Compression	Gas Compressor Sets	Generation Sets	Water Injection Pumps
2019 Q1	97.93	97.14	98.99	99.62	100
2019 Q2	99.93	97.50	99.62	99.94	100
2019 Q3	99.47	97.47	96.84	100	100
2019 Q4	95.84	100	99.02	99.19	100
2020 Q1	99.56	100	99.63	99.91	83.26
2020 Q2	99.30	100	99.62	97.43	86.96
2020 Q3	97.42	100	99.43	99.76	98.06
Failure	7TC-2920 high bearing vibration – Engine change out. Back online Nov 2019		00TC-2410 turbine blade – Repair complete. Unit online Dec 2019		00P-5155B damaged thrust bearing and leaking mechanical seal. -Replacement pump online April 2020
Failure	7TC-2920 engine failed to crank – Engine change out and RCFA in progress		00TC-2310 turbine blade failure – Engine change out. Back online Aug 2019		00P-5155B high vibration. – shorted cable replaced.

Table 10.23: PM3 Major Equipment Availability

During 2018-2020 there were three (3) early life failures of Solar turbines at PM3 South. The probable cause is due to inefficiency of the air intake filtration system. These units were installed in 2013. There is potential deterioration of the intake systems may have contributed to the failures. Repsol suggested the older turbine units may require upgrades to the air intake systems to incorporate more recent improvements to design and components.

10.7.2.2 Kinabalu Major Equipment Availability

KNDP-A has installed redundancy in power generation and crude oil transfer pumps providing high system availability (Table 10.24). Individual Power generation units normally have a high availability however GQ7510 suffered and engine failure in December 2019.

HP compressor had low reliability in 2019 with failures generally attributed to high vibration. Following repairs of pipework and fittings due to vibration induced cracking availability to mid-2020 is high. The recently deferred gas debottlenecking project includes addressing the HP compressor vibration issue.

Kinabalu has been without back up power generation from December 2019 until the replacement engine was installed in Q3 2020. Engine performance experienced rapid deterioration prompting the change out however no information was available on the cause.

	HP Compressor K2500	LP Compressor K2430	Power Generator GQ7510	Power Generator GQ7520	COTP P1310	COTP P1320
Oct 2019	93.28	99.48	100	94.76	99.73	100
Nov 2019	96.20	99.58	50	99.86	99.72	100
Dec 2019	99.06	100	0	100	100	100
2019 Ave	87.62	99.13	80.64	97.28	99.42	99.82
Jan 2020	99.33	100	0	100	100	100
Feb 2020	99.07	100	0	100	100	100
Mar 2020	94.35	100	0	99.19	100	100
Apr 2020	99.95	100	0	100	100	100
May 2020	100	100	0	100	100	100
June 2020	96.96	99.76	0	100	100	100
2020 YTD	98.27	99.96	0	99.87	100	100
Failures	Vibration induced hair line fractures on suction bottles - repaired		Faulty ECU card - replaced			
	Cooling water pump leaks – pump replaced		Engine failed to start due to deteriorating performance – change out engine planned July 2020			
	Suction and discharge valve failures – replaced					
	Low fairing temperature – replaced cylinder head					

Table 10.24: Kinabalu Major Equipment Availability

10.8 Asset Age and Asset Life Extension

10.8.1 PM 3 Asset Age and Asset Life Extension

PM3 was developed over numerous phases with early production commencing in 1997 from BKA LWS wellhead platform to an FPSO (since retired). In 2003 PM3 South main development came on stream with the addition of wellhead platforms BKC, BSA, BRB, BRA CPP, BRD MOAB and FSO PM3. In 2005 BRAU extension to BRA housing additional water injection, and BRE GPP & vent jacket were added. BTA wellhead platform was installed in 2006. There has also been deck extension/annex for additional well slots at BKA and BKC. A redundant glycol contactor at BRA was converted to a gas mercury removal unit in 2008. A dedicated gas lift compressor was added at BRD in 2016.

In 2008 PM3 North development came on steam with BOB and BOC wellhead platforms and BOA CCP and flare jacket. BPA was added in 2018.

Under Petronas regulation (PPGUA) the PSC contractor must conduct an Asset Life Extension study should commence 5 years before the end of design life, excluding of uneconomic fields. Based on this, in PM3 South, ALE studies should have commenced for seven (07) installations within the last three (03) years and one (01) in 2021, details below (Table 10.25).

No.	Installation	Installed (Year)	Design Life	Start of ALE by
1	BRB	2002	20	2017
2	BSA	2002	20	2017
3	BRA	2003	20	2018
4	BRC	2003	20	2018
5	BRD	2003	20	2018
6	BKC	2003	20	2018
7	BRE	2005	20	2020
8	BTA	2006	20	2021

Table 10.25: PM3 South ALE Schedule

In PM3 North, ALE study for five (05) installations is due in 2022, details in Table 10.26.

No.	Installation	Installed (Year)	Design Life	Start of ALE by
1	BOA	2007	20	2022
2	BOB	2007	20	2022
3	BOC	2007	20	2022
4	BOD	2007	20	2022
5	BOE	2007	20	2022
6	BPA	2018	15	2027

Table 10.26: PM3 North ALE Study

Asset life extension studies have been conducted for and BKA annex. This Structure was installed in 1997 with design life of 20 years. Preparation and finalisation of a report associated with the study is currently underway. It may not be timely available for evaluation and assessment. However, Repsol has assured that the structure is fit-for-service beyond 10 years PSC subject to no further modification or weight addition.

BRD (MOAB) ALE Study was initiated in 2020, however not details were available at the time of evaluation. A Tilt and Rotation analysis has been undertaken in addition to the Non-Liner Push Over analysis due to existing jacket tilting and flooded legs.

The table below contains jacket design life, remnant life and planned date for ALE Study (Table 10.27). The Repsol Structural-UWI Plan 2020 includes ALE studies for all assets with BSA, BRB and BRA + Annex commencing 2021.

	Platform/Facility	Process Facilities	Installed	Design Life	Remnant Life	ALE Study Planned
PM3 South	**BKA**	Wellhead	1997	20		In progress
	BKA annex	Wellhead and risers	2001	20		In progress
	BKC + annex	Wellhead and risers	2003 & 2007	20	2	2022
	BSA	Wellhead and risers	2001	20	0	2021
	BRC	Wellhead and risers	2003	20	2	2022
	BRB	Wellhead and risers, bridge linked to BRA	2003	20	2	2021
	BRA + annex (BRAU)	Oil and gas separation, mercury removal water treatment and disposal, oil transfer to FSO, gas compression and sales and seawater treatment and injection.	2003	20	2	2021
	BRD (MOAB)	Risers, oil and gas separation, gas compression, bridge linked to BRA.	2003	20	2	In progress
	FSO PM3	Oil reception, storage, water disposal, oil offloading and sales metering	2003			N/A
	BRE	Gas conditioning, CO2 removal and venting, bridge linked vent/flare, bridge linked to BRD	2005	20	4	2024
	BRE Vent	Vents & flare tripod bridge linked to BRE	2005	20	4	2024
	BTA	Wellhead and risers	2006	20	5	2022
PM3 North	**BOA**	Oil and gas separation, mercury removal, water treatment and disposal, oil transfer to FSO, gas compression and export and seawater treatment and injection, bridge linked flare.	2007	20	6	2027
	BOE	Flare tripod bridge linked to BOA	2007	20	6	2027
	BOB	Wellhead and risers	2006	20	6	2026
	BOD	Wellhead and risers, bridge linked	2007	20	6	2026
	FSO Orkid	Oil reception, storage, water disposal, oil offloading and sales metering	2007			N/A
	BPA	Wellhead and risers	2017	15	11	2033

Table 10.27: PM3 ALE Study

Several process simplification projects have been identified at PM3 South complex in the 2020 AMIR although no cost benefit analysis was provided (Table 10.28).

Field	Platform	Area	Description	Justification
PM3 South	BRA	LP Compressor	Removal of compressor	No longer required due to minimum LP gas recovery. Cost of rejuvenation plus O&M versus LP gas recovery value
	BRD	Turbine Generator 7TG-8018	Removal of turbine generator	Power supply from BRA 3 TG. BRD unit not required.
	BRE	Secondary Propane Chiller HX-9572	Isolation of chiller HX-572	HX-9572 not required to cool down permeate gas feed to secondary membranes
	BRE	Feed Gas / Export Gas Exchanger HX-9015	Isolation of exchanger HX-9015	Reduce BRE plant pressure drop for gas production optimisation

Table 10.28: PM3 Process Simplification

10.8.2 Kinabalu Asset Age and Asset Life Extension

Kinabalu was initially developed by KNDP-A an integrated wellhead and processing platform in 1997. Produced water treatment and disposal was added in 2015. In 2017 KNDW-D wellhead platform was added (Table 10.29).

Platform	Process Facilities	Installed	Design Life	Remnant Life	ALE Study Planned
KNDP-A	Wellhead, oil and gas separation, water treatment and disposal, oil export, gas compression and export, water injection	1997	20	11 (2032)	Complete 2019
KNDW-D	Wellhead riser, bridge linked to KNDP-A	2017	20	16	2036

Table 10.29: Kinabalu ALE Study

Repsol commissioned an Asset Life Extension study for KNDP-A in 2019. The study concluded the asset life could be extend for a further 15 years past design life to 2032. The study had reported a total 114 findings of which eight (08) areas requiring remedial action (red), forty-four (44) areas requiring further investigation (amber) and sixty-two (62) areas where no action required (green), detailed in Table 10.30.

	Pipelines	Electrical & Instruments	Rotating	Static	Fire Safety	Structural
Action Required	2	0	1	1	4	0
Further investigation	8	19	13	3	1	0
Nothing identified	4	4	27	17	6	4

Table 10.30: KNDP-A ALE Study

Based on the information provided by Repsol as of 26 October 2020, five (5) yellow action remain open and two (2) are planned for execution. The two (02) pipeline related red actions and the one (01) rotating related action are yet to be fully addressed, detailed in Table 10.31 below.

No	Equipment Title	Cat.	Recommendation	One time / Annual Cost	Action	Year	Status	Remarks
DNVGL Costing Report 5-01	12" oil pipeline	Red	One campaign to rectify all free spans.	US$ 1,000,000	Free spans to be monitored / verified in 2020 ROV programme		Open	Spans may require rectification following ROV survey
DNVGL Costing Report 5-02	14" gas pipeline	Red	One campaign to rectify all free spans.	US$ 1,000,000	Free spans to be monitored / verified in 2020 ROV programme		Open	Spans may require rectification following ROV survey
DNVGL Costing Report 6-09	Rotating			Included in gas project			Planned	Spare parts ordered for hot standby and replacement included in gas debottlenecking project 2023
DNVGL Costing Report 5-07	Firewater System	Yellow	Repsol need to confirm there will not be any drilling activity in the next 15 years. If drilling is required, firewater system must be reinstated and restored to working condition. Further details are provided in Section 6 recommendations.	US$ 5,000,000	Replace equipment	2018	Open	To assign EIC to review this action item. HSE or Ops?
DNVGL Costing Report 5-08	Electrical & Instrument (Overall)	Yellow	Perform an update to the CMMS/SAP on equipment manufacturer and model based on Asset Verification Report by ARAMIS in 2015. Adequacy of spares shall follow Repsol's Maintenance Philosophy. A replacement program for obsolete equipment is proposed to be done with priority given to the equipment with higher criticality as the failure of the equipment would translate into a greater production/economic loss and safety.	US$ 1,400,000	Upgrade/ replace E&I equipment	2019	Open	To assign EIC to review this action item.

No	Equipment Title	Cat.	Recommendation	One time / Annual Cost	Action	Year	Status	Remarks
DNVGL Costing Report 5-09	EX and IP Equipment	Yellow	Rectification exercise to be performed based on visual inspection and verification on field instrument body assembly, cables and thread lubrication during preventive maintenance (PM). Perform full close out of recommendations and gap from survey on instrument tubing AIMS-FSIMS-PRE-KNDPA-160216(SWAGLOK) and Ex Integrity Study 2016. The classification is to be revisited once the close out report on findings and action items from the Ex Inspection and Instrument Tubing Survey are available.	Refer 5-8	Upgrade/ replace equipment	2019	Open	To assign EIC to review this action item.
DNVGL Costing Report 5-13	Pipeline crossing	Yellow	Carry out strength and fatigue analyses for the crossing (This is consistent with method applied for the subsea structure of the jacket. The analysis should be carried out whenever possible and latest in 2019.)	US$ 200,000	Perform analysis	2018	Planned	Scope and study to be determined, reschedule the study to 2021. Year of assigned action may not be feasible due to contract unavailability
DNVGL Costing Report 5-14	Risers	Yellow	Carry out riser strength and fatigue analyses (This is consistent with method applied for the subsea structure of the jacket. The analysis should be carried out whenever possible and latest in 2019.)	US$ 200,000	Perform analysis	2018	Planned	Scope and study to be determined, reschedule the study to 2021. Year of assigned action may not be feasible due to contract unavailability
DNVGL Costing Report 6-11	Fire & Gas detector: H2 detector	Yellow	To update PS001 on the requirement for H2 detectors to trip the battery chargers. The need for H2 detectors are to be reconsidered and taking into account the existing Fire and Gas detection system design and safety philosophy.	-	Update as-is documents	2018	Open	To assign EIC to review this action item.

No	Equipment Title	Cat.	Recommendation	One time / Annual Cost	Action	Year	Status	Remarks
DNVGL Costing Report 7-13	Gas Turbine Generator	Yellow	PM Test: Partial (3-5 yearly) and Full (5-10 yearly) To perform Rotor test: 1. Rotor winding resistance/impedance 2. Recurrent Surge Oscillograph/air gap Flux probe test 3. Diode and RTD checks 4. DP/UT on retaining rings, slip rings, shaft, fan blades, bearings. 5. Winding resistance/impedance measurement of main and pilot exciter stator/rotor To perform Stator windings test 1.Polarisation Depolarisation Current Analysis 2. Tan Delta and Capacitance Analysis 3. Non-Linear Insulation Behaviour Analysis 4. Partial Discharge Analysis. 5. Stator Winding Resistance/Coupling resistance 6. Wedge Tightness Check 7. Electromagnetic Core Imperfection Detection test	Normal operating budget	PM	2019	Open	To assign EIC to review this action item.
DNVGL Costing Report 7-30	Actuated valves	Yellow	Valve performance to be monitored in the next ESD Test for KNDPA. The failure rate of the valve is also recommended to be properly recorded and serve as an input in the next cycle of IPF study. Perform verification and rectification exercise for valves with corrosion on actuator body and accessories by performing leak check on actuator, monitoring of valve stroking time and inspection on physical deformation and defect.	Normal operating budget	Monitor equipment & PM	2018	Open	To assign EIC to review this action item.

Table 10.31: Status of Outstanding Actions

One process improvement project has been identified at KNDP-A in the 2020 AMIR although no cost benefit analysis was provided (Table 10.32).

Field	Platform	Area	Description	Justification
Kinabalu	KNDP-A	Environment	Install 2nd Hydrocyclone Unit	Increase capacity of PWT system to cater for higher water cut and reduce LCOT processing tariff

Table 10.32: Kinabalu Process Simplification

10.9 Incremental OPEX and Availability Assumptions

The conclusion from the reviews conducted is that additional funds should be allowed in future maintenance budgets over and above the maintenance allowed for in Repsol forecasts.

10.9.1 Platform Structures Maintenance

Based on the limited data available, it can be concluded that there are no immediate concerns with the majority of the platform structures. However, the concerns related to BRD MOAB tilting, scouring at BOA jacket legs and PM3 North installations anodes depletion which will need to be appropriately and timely addressed.

It is unclear if the proposed remedial solution to address the tilting of BOD MOAB will be fully mitigated the concern. However, it is recommended to have US$ 4 million included in 2023 to cover a potential subsea repair of the BOD legs.

BKA light-weight structure may require remedial work to extend its operational life till the end of the PSC and further. It is also recommended to have another US$ 4 million allocated in 2023 to complete the required potential remedial work.

Similarly, it is not evident if funds have been allocated in the 2021 WP&B to retrofit depleted anodes at PM3 North installations. On that basis, it is recommended to have US$ 2 million included in 2023 for this scope.

It is recommended to allow adequate funds post PSC extension for jacket repairs to extend operational life. With no details of actual condition of the jackets both underwater and above water, it is not possible to specify the required remedial work without structural analysis. It is recommended to allocate US$ 2 million every 2 years over initial 10 years post PSC extension for remedial work to extend structural life.

10.9.2 Platform Topsides Maintenance

PM3 no evident significant additional costs for topsides maintenance or equipment obsolescence until end of PSC. The ALE Studies when completed will identify potential costs to extend the safe operation life to the topsides process and equipment.

Kinabalu ALE scopes costs for electrical equipment included in 2021WP&B. Fire pump is not included. It is understood the fire pump is only required when a drilling rig is over the KNDP-A platform. Repsol are evaluating the requirement to install a fire pump on a not normally manned installation. The cost of the fire pump and other upgrades to the fire water system is US$ 5 million based on the ALE study. At this time, it not recommended to include this cost.

10.9.3 Pipeline Maintenance

The PM3 CAA WP&B of 2021 for Pipeline System inspection and maintenance is valued at MYR 22.355 million. For 2022 the value reduces to MYR 5.983 million and further reduces to MYR 5.289 million by 2025. The tasks that the annual WP&B allocated for are intelligent pigging, operational pigging, insulation cover remediation, concrete mattress placement, free-span rectification and scoring rectification.

Without full details, it appears that the PM3 2021 WP&B includes the cost for installation of insulation on BTABRC14PL and BKABRC10PL to mitigate Top of Line corrosion and, placement of concrete mattresses on four (04) pipelines that have suffered mechanical damage and displacement due to anchor drag have also been included.

In addition to the PM3 CAA 2021 WP&B, it is recommended to allocate US$ 15 million for subsea expansion spool replacement for BKABRC10PL, BKCBSA20PL and BRBBKA4GL riser repair for in 2023. A further US$ 15 million is recommended to be allocated for pipeline sectional replacements between 2027 and 2037. And finally, another US$ 20 million from 2037 to projected end of economic life in 2043 for pipeline remedial works to extend operational line. In summary, a total of US$ 60 million periodic allocation is recommended for pipeline remedial works from 2023 till the end of field-economic life.

Kinabalu 2021 WP&B submission contains no allocated funds for Pipeline inspection and maintenance for that year. This is based on the assumption that the present pipeline free spans are not an integrity threat. This is subject to the findings form the 2021 underwater inspection findings. However, an allocation of US$ 2 million is recommended in 2023 to rectify the critical spans.

10.9.4 Incremental Planned Shutdown Days & Availability Benefits

There has been no major rectification work identified which would require significant addition shutdown days to rectify. PM3 annual turnaround alternates between 14 and 7+2(start-up) days. Kinabalu annual turnaround is scheduled for 1+3(start-up) and 10+3(start-up) alternate years.

11 ECONOMIC EVALUATION

11.1.1 Contractual Rights Overview

PM3 CAA PSC overview and its fiscal terms, as used to conduct commercial evaluation; Unitisation Agreement its Tract participation and Unit Participation are presented in Table 11.1 to Table 11.3.

PM3 CAA PSC	
Contractors / Participating Interest	PETRONAS Carigali (35.0%) Repsol Malaysia Oil and Gas Limited (22.3%) Repsol Malaysia Oil and Gas (PM3) Limited (12.7%) PVEP (30.0%)
Scope	Governs the exploration, development activities, and production of liquids and natural gas in PM3 CAA Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 16th February, 1989 PSC extension has been granted for a further term ending on 31st December 2027
Royalty	As per PSC terms
Cost Liquids / Gas	As per PSC terms
Unused Liquids / Gas and Available Profit Liquids / Gas	As per PSC terms
Research Cess	As per PSC terms
Export Duty	As per PSC terms
Supplementary Payment:	As per PSC terms
Petroleum Income Tax rate	38%
Extension bonus payment	As per PSC terms
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.

Table 11.1: PM3 CAA PSC Fiscal Terms

Unitisation Agreement of PM3 CAA	
Counterparties	PETRONAS PetroVietnam
Scope	Establishes the creation of East Bunga Kekwa – Cai Nuoc unitised field that overlaps the boundary lines between Peninsular Malaysia and Vietnam Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 10 February 2000
Tract participation and Unit Participation	As presented in Table 11.3

Table 11.2: PM3 CAA Unitisation Agreement

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
PM3 CAA		75.9508%	
Repsol Oil & Gas Malaysia Limited	22.33%		16.96%
Repsol Oil & Gas Malaysia (PM3)	12.67%		9.62%
PETRONAS Carigali	35.00%		26.58%
PVEP	30.00%		22.79%
Block 46 (Cai Nuoc)		24.0492%	
Repsol	70.00%		16.83%
PVEP	30.00%		7.21%
Total		100.00%	100.00%

Table 11.3: PM3 CAA Unitisation Agreement Tract participation and Unit Participation

Summaries of Gas Sales and Purchase Agreement key glossaries and terms are presented in Table 11.4 and Table 11.5.

Upstream Gas Sales Agreements (UGSA)	
Singing Date	10th February, 2000
Term	Initial term was for a period of 10 years and was extended until end of the existing PSC term (31 December 2027)
Counterparty	PETRONAS PetroVietnam PM3 CAA contractors: PETRONAS Carigali (35%), Repsol Malaysia Oil and Gas Limited (22.33%), Repsol Malaysia Oil and Gas (PM3) Limited (12.67%), PVEP (30%)
Scope	The contract lays down the obligations of both the Repsol, the PM3 CAA contractors, and the buyers, PETRONAS and PetroVietnam The contract defines the quality, quantity and price of the gas sold from the field
Delivery	The PM3 CAA contractors have to deliver the contracted gas capacity to PETRONAS or PetroVietnam delivery points, where the ownership of the gas will be transferred to PETRONAS or PetroVietnam respectively In case the PM3 CAA contractors fails to deliver the contracted daily quantity to either PETRNAS or PetroVietnam, they have to deliver the "Penalty Quantity" in the following year Penalty Quantity is the difference between the contracted daily quantity and quantity delivered at delivery point The first delivery of gas in any year will be deemed to be the Penalty Quantity accrued in preceding year
Pricing	As per UGSA terms

Table 11.4: Upstream Gas Sales Agreements (UGSA) Key Terms

Annual Delivery Quantity (ADQ) and Daily Average						
Year	**Total ADQ (Bscf)**	**PETRONAS ADQ (Bscf)**	**PetroVietnam ADQ (Bscf)**	**Total daily average (MMscfd)**	**PETRONAS daily average (MMscfd)**	**PetroVietnam daily average (MMscfd)**
2021	74.8	37.4	37.4	205.0	102.5	102.5
2022	74.8	37.4	37.4	205.0	102.5	102.5
2023	74.8	37.4	37.4	205.0	102.5	102.5
2024	63.5	31.8	31.8	174.0	87.0	87.0
2025	58.4	29.2	29.2	160.0	80.0	80.0

Table 11.5: Annual Delivery Quantity (ADQ) and Daily Average

Block 46 PSC overview and its fiscal terms, as used to conduct commercial are presented in Table 11.6.

Block 46 (Cai Nuoc)	
Contractors / Participating Interest	Repsol[1] (70%) PVEP (30%)
Scope	Governs the redevelopment activities and production of liquids and natural gas in Block 46 (Cai Nuoc) Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism
Effective Date and Duration	Effective as of 8 August 1990; valid for 25 years until 2015 PSC was first extended until 15 Feb 2017 for crude oil and 13 Dec 2018 for natural gas A second extension was subsequently granted until 31 Dec 2027 for both crude oil and natural gas
Cost Liquids / Gas	As per PSC terms
Profit Liquids / Gas	As per PSC terms
Export Duty	As per PSC terms
Training Fee	As per PSC terms
Corporate Income Tax rate	Paid on behalf of Contractor by Government (Corporate Tax Rate of 50%)
Production Bonus	As per PSC terms

1) Denotes operator

Table 11.6: Block 46 (Cai Nuoc) PSC Fiscal Terms

Block 46 PSC overview and its fiscal terms, as used to conduct commercial are presented in Table 11.7.

Kinabalu PSC	
Contractors / Participating Interest	Repsol 60%1) PETRONAS Carigali 40%
Scope	Governs the redevelopment activities and production of liquids and natural gas in Kinabalu. Sets out each Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 26th December, 2012 Contract valid for 20 years until 25th December, 2032
Royalty	As per PSC terms
Cost Liquids / Gas	As per PSC terms
Unused Liquids / Gas:	As per PSC terms
Available Profit Liquids / Gas:	As per PSC terms
Research Cess	As per PSC terms
Export Duty	As per PSC terms
Sabah Sales Tax2)	As per PSC terms
Supplementary Payment:	As per PSC terms
Petroleum Income Tax rate	38%
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.

1) Denotes operator; Repsol relinquished its associated gas rights effective from April 2015
2) The Sabah state government has implemented a 5% state sales tax on all petroleum products, mainly crude petroleum oil, natural gas (except for the natural gas used for the purpose of processing into LNG and natural gas sold o Sabah Energy Corporation Sdn Bhd), and liquefied gas, under Section 10 (1) of the State Sales Tax Enactment 1988, effective from 1 Apr 2020. Crude oil is exported from Labuan; therefore, Sabah Sales Tax is not be applicable in the valuation.

Table 11.7: Kinabalu PSC Fiscal Terms

PM305 / PM314 PSC overview and its fiscal terms, as used to conduct commercial evaluation; Unitisation Agreement its Tract participation and Unit Participation are presented in Table 11.8 to Table 11.12.

PM305 / PM314 PSC	
Contractors / Participating Interest	Repsol 60%[1)] PETRONAS Carigali 40%
Scope	Governs the exploration, development activities and production of liquids and natural gas in PM305. Sets out the Contractor's responsibilities and commitments as well as terms on allocation of output (for royalty and profit crude oil / natural gas) and cost recovery mechanism.
Effective Date and Duration	Effective as of 27th November, 2000 (PM305) / 31st March, 2004 (PM314) Contract valid for 29 years until 27th November, 2029 (PM305) / 31st March, 2033 (PM314)
Royalty	As per PSC terms
R/C Factor	As per PSC terms
Research Cess	As per PSC terms
Export Duty	As per PSC terms
Supplementary Payment:	As per PSC terms
Petroleum Income Tax rate	38%
Abandonment Cess	Facilities abandonment costs are deposited in an escrow account according to the ratio of production to remaining reserves. Wells abandonment costs are recovered as paid.

*1) Note: * Denotes operator; separate agreements exist each for PM305 / PM314*

Table 11.8: PM305 / PM314 PSC Fiscal Terms

Unitisation Agreement of PM305 and PM314	
Contractors / Participating Interest	PM305 – Repsol (60%), PETRONAS Carigali (40%) PM314 – Repsol (60%), PETRONAS Carigali (40%)
Scope	Establishes the creation of a unitised field combining the PM305 and PM314 tracts Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 14 August 2005
Tract participation and Unit Participation	As presented in Table 11.10

Table 11.9: Unitisation Agreement of PM305 and PM314

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
PM 305		92.90%	
Repsol	60.00%		55.74%
PETRONAS Carigali	40.00%		37.16%
PM 314		7.10%	
Repsol	60.00%		4.26%
PETRONAS Carigali	40.00%		2.84%
Total		**100.00%**	**100.00%**

Table 11.10: PM305 and PM314 Unitisation Agreement Tract Participation and Unit Participation

Unitisation Agreement of PM305 and GPSC	
Contractors / Participating Interest	PM305 – Repsol (60%), PETRONAS Carigali (40%) GPSC – PETRONAS Carigali (50%), ExxonMobil (50%)
Scope	Establishes the creation of Angsi Southern Channel unitised field combining parts of PM305 and GPSC fields Provides for the joint administration and management of as well as for the sharing of hydrocarbons in the unitised field
Effective Date	Effective as of 18th March 2004
Tract participation and Unit Participation	As presented in Table 11.12

Table 11.11: Unitisation Agreement of PM305 and GPSC

Petroleum Contract	Group Interest	Tract Participation	Unit Participation
GPSC		71.40%	
PETRONAS Carigali	50.00%		35.70%
ExxonMobil	50.00%		35.70%
PM 305		28.60%	
Repsol	60.00%		17.20%
PETRONAS Carigali	40.00%		11.40%
Total		**100.00%**	**100.00%**

Table 11.12: Unitisation Agreement of PM305 and GPSC Tract Participation and Unit Participation

11.1.2 Petroleum Pricing Basis

The valuation has been based on the RPS Q2 2021 long term forecast for Brent (forward curve between 2021 and 2029; long term price of US$ 60 per barrel flat real at 2 per cent per annum thereafter) as shown in Table 11.13.

Based on the historical Tapis crude oil and condensate prices provided by Repsol, PM3 CAA crude oil and condensate, PM305 / PM314 crude oil, as well as Kinabalu crude oil were traded at a 5% premium to Brent, respectively. A summary of PM3 CAA, PM305, and Kinabalu crude oil price, PM3 CAA condensate price, and the implied gas price based on the gas pricing formula in UGSA is presented in Table 11.4.

Year	RPS Brent	PM3 CAA Crude Oil	PM305/PM314 Crude Oil	Kinabalu Crude Oil	PM3 CAA Condensate	PM3 CAA gas price
	US$/bbl	US$/bbl	US$/bbl	US$/bbl	US$/bbl	US$/Mscf
2021	60.0	62.9	62.9	62.9	62.9	3.9
2022	57.0	59.7	59.7	59.7	59.7	3.7
2023	55.0	57.6	57.6	57.6	57.6	3.6
2024	53.0	55.5	55.5	55.5	55.5	3.5
2025	55.0	57.6	57.6	57.6	57.6	3.6
2026	58.0	60.8	60.8	60.8	60.8	3.9
2027	60.0	62.9	62.9	62.9	62.9	4.0
2028	63.0	66.0	66.0	66.0	66.0	4.2
2029	68.0	71.3	71.3	71.3	71.3	4.5
2030	71.7	75.1	75.1	75.1	75.1	4.8
2031	73.1	76.6	76.6	76.6	76.6	4.9
2032	74.6	78.2	78.2	78.2	78.2	5.0

Table 11.13: RPS Price Forecast; PM3 CAA and Kinabalu Crude and Condensate Realised Price Forecast, and Implied Gas Price Forecast

11.1.3 Cashflow Analysis

The Economic Limit Test ("ELT") performed for the determination of Reserves is based on RPS's estimates of recoverable volumes, a review of the Company's estimates of Capex and Opex, and inclusion of other financial information and assumptions, as outlined in Capex, Opex and Abex sections.

The PSC is assumed to reach its economic limit when the cumulative value of its operating cash flow ceases to increase. All projects to be classified as Reserves must be economic under defined conditions[56]. RPS has therefore assessed the future economic viability of each case on the basis of its post-tax undiscounted Net Cash Flow MOD.

An annual inflation rate of 2 per cent has been built into the ELT. This inflation rate has also been applied to all cost estimates to adjust them from 2021 dollars to MOD.

The effective date of this report is 1st January, 2021 and this has been used as the discount date for the valuation.

[56] PRMS 2018: 3.1.2.1 Economic determination of a project is tested assuming a zero percent discount rate (i.e., undiscounted). A project with a positive undiscounted cumulative net cash flow is considered economic.

COMPETENT PERSON'S REPORT IN RELATION TO THE RESERVES AND RESOURCES EVALUATION OF THE ASSETS (CONT'D)

The net present values at various discount rates attributed to Repsol for PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/PM314 PSC are presented in Table 11.14 to Table 11.15. Table 11.18 summarises the consolidated net present values at various discount rates attributed to Repsol.

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	46	53	54	56
1P	**2025**	**38**	**41**	**41**	**42**
2PD	2027	120	113	111	110
2P	**2027**	**170**	**146**	**142**	**137**
3PD	2027	241	203	196	189
3P	**2027**	**284**	**234**	**224**	**215**

Table 11.14: PM3 CAA PSC Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2026	53	54	54	54
1P	**2027**	**77**	**74**	**73**	**72**
2PD	2032	147	128	123	120
2P	**2032**	**188**	**157**	**150**	**145**
3PD	2032	259	202	191	182
3P	**2032**	**293**	**227**	**215**	**204**

Table 11.15: Kinabalu PSC Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2025	(5)	(3)	(3)	(3)
1P	**2025**	**(5)**	**(3)**	**(3)**	**(3)**
2PD	2027	2	3	3	3
2P	**2027**	**2**	**3**	**3**	**3**
3PD	2027	10	9	9	9
3P	**2027**	**10**	**9**	**9**	**9**

Table 11.16: B46 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	ELT Date	Post-Tax Net Present Value (US$ Million, MOD)			
		0%	8%	10%	12%
1PD	2024	(9)	(10)	(10)	(10)
1P	**2024**	**(9)**	**(10)**	**(10)**	**(10)**
2PD	2024	(10)	(10)	(10)	(10)
2P	**2024**	**(10)**	**(10)**	**(10)**	**(10)**
3PD	2024	(9)	(10)	(10)	(10)
3P	**2024**	**(9)**	**(10)**	**(10)**	**(10)**

Table 11.17: PM305/PM314 PSC – Post-Tax Valuation at RPS Base Case Price Scenario

	Post-Tax Net Present Value (US$ Million, MOD)			
	0%	8%	10%	12%
1PD	84	94	96	97
1P	**102**	**102**	**102**	**101**
2PD	259	233	228	222
2P	**351**	**296**	**285**	**275**
3PD	500	404	386	370
3P	**578**	**460**	**438**	**418**

Table 11.18: Consolidated (PM3 CAA PSC, Kinabalu PSC, B46 PSC, and PM305/PM314 PSC) Post-Tax Valuation at RPS Base Case Price Scenario

11.2 Reserves and Resources

Full Field Gross Reserves by field and Hibiscus Net Entitlement Reserves are presented in Table 11.19 to Table 11.22.

SUMMARY OF OIL RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	14.0	17.7	21.1	29.8	25.6	39.0	3.2	4.0	4.6	6.6	5.4	7.9
B46[3]	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**26.6**	**33.7**	**46.3**	**58.9**	**61.1**	**79.5**	**8.2**	**10.4**	**14.5**	**17.9**	**18.4**	**22.6**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] Zero 1PD and 1P as B46 Low Estimate does not pass economic limit test

[4] Zero Reserves as Low, Best, and High Estimate do not pass economic limit test

[5] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 11.19: Oil Reserves as of 1 January 2021

SUMMARY OF GAS RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (Bscf)						Hibiscus Net Entitlement Reserves[2] (Bscf)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	214.3	217.3	368.5	377.5	535.2	549.2	48.5	49.0	80.8	83.6	112.9	112.5
B46												
Kinabalu												
PM305/314												
Total[3]	**214.3**	**217.3**	**368.5**	**377.5**	**535.2**	**549.2**	**48.5**	**49.0**	**80.8**	**83.6**	**112.9**	**112.5**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 11.20: Gas Reserves as of 1 January 2021

SUMMARY OF CONDENSATE RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMstb)						Hibiscus Net Entitlement Reserves[2] (MMstb)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	6.6	6.8	11.5	12.1	15.6	16.6	1.5	1.5	2.5	2.7	3.3	3.4
B46												
Kinabalu												
PM305/314												
Total[3]	**6.6**	**6.8**	**11.5**	**12.1**	**15.6**	**16.6**	**1.5**	**1.5**	**2.5**	**2.7**	**3.3**	**3.4**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment.

Table 11.21: Condensate Reserves as of 1 January 2021

SUMMARY OF RESERVES
As of 1 January 2021
BASE CASE PRICES AND COSTS

	Full Field Gross Reserves[1] (MMboe)						Hibiscus Net Entitlement Reserves[2] (MMboe)					
	1PD	1P	2PD	2P	3PD	3P	1PD	1P	2PD	2P	3PD	3P
PM3 CAA	56.4	60.7	94.0	104.8	130.4	147.1	12.8	13.7	20.7	23.3	27.5	30.1
B46	0.0	0.0	1.0	1.0	1.3	1.3	0.0	0.0	0.4	0.4	0.6	0.6
Kinabalu	12.6	16.1	24.2	28.1	34.1	39.2	5.0	6.4	9.4	10.8	12.4	14.1
PM305/314	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total[3]	**68.9**	**76.8**	**119.2**	**134.0**	**165.9**	**187.6**	**17.7**	**20.1**	**30.5**	**34.5**	**40.5**	**44.8**

Notes:

*[1] Gross field Reserves (100% basis) **after** economic limit test*

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1P Reserves may be a very conservative assessment and the total 3P Reserves a very optimistic assessment. 1 January 2021

Table 11.22: Summary of Reserves in Oil Equivalent Barrels as of

11.3 Contingent Resources Summary

A summary of Contingent Resources for the Assets is provided in Table 1.16 to Table 1.18 below for Oil, Gas, and Barrels of Oil Equivalent, respectively. RPS did not conduct any independent review of Repsol's estimates of these activities.

The full field gross Best Estimate for both oil and gas are sourced directly from Repsol's economic model. In order to derive the full field gross Low Estimate and High Estimate, RPS has applied the ratio of full field gross 1P over full field gross 2P and the ratio of full field gross 3P over full field gross 2P respectively to the Best Estimate. Net Entitlement Contingent Resources for Low Estimate, Best Estimate, and High Estimate are derived based on the ratio of Net Entitlement over full field gross Reserves.

SUMMARY OF OIL CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMstb)			Hibiscus Net Entitlement Contingent Resources[2] (MMstb)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	6.2	10.5	12.6	1.4	2.3	2.6
PM3 CAA	NW BR Infill	1.4	2.4	2.8	0.3	0.5	0.6
PM3 CAA	Production Efficiency	0.3	0.4	0.5	0.1	0.1	0.1
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**8.1**	**13.7**	**16.4**	**1.9**	**3.1**	**3.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC.

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 11.23: Oil Contingent Resources as of 1 January 2021

SUMMARY OF GAS CONTINGENT RESOURCES
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (Bscf)			Hibiscus Net Entitlement Contingent Resources[2] (Bscf)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	8.0	13.9	18.7	1.8	3.1	3.8
PM3 CAA	NW BR Infill	0.6	1.0	1.3	0.1	0.2	0.3
PM3 CAA	Production Efficiency	3.8	6.6	8.9	0.9	1.5	1.8
Total[3]		**12.4**	**21.5**	**29.0**	**2.8**	**4.8**	**5.9**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 11.24: Gas Contingent Resources as of 1 January 2021

SUMMARY OF CONTINGENT RESOURCES (BOE)
As of 1 January 2021
BASE CASE PRICES AND COSTS

		Full Field Gross Contingent Resources[1] (MMboe)			Hibiscus Net Entitlement Contingent Resources[2] (MMboe)		
	Project	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
PM3 CAA	Raya post Seismic	7.6	12.9	15.7	1.7	2.9	3.2
PM3 CAA	NW BR Infill	1.5	2.5	3.1	0.3	0.6	0.6
PM3 CAA	Production Efficiency	0.9	1.5	2.0	0.2	0.3	0.4
Kinabalu	Production Efficiency	0.2	0.4	0.5	0.1	0.1	0.2
Total[3]		**10.2**	**17.3**	**21.3**	**2.3**	**3.9**	**4.4**

Notes:

[1] Gross field Contingent Resources (100% basis) until the current expiry of the PSC

[2] Company's net entitlement, which exclude the Malaysia Government's share under the PSC after economic limit test. Reported at PSC level only.

[3] PRMS recommends that for reporting purposes, assessment results should not incorporate statistical aggregation beyond the field, property or project level. The total Reserves are therefore the product of arithmetic addition and as such are not statistically correct. As a result, the total 1C Contingent Resources may be a very conservative assessment and the total 3C Contingent Resources a very optimistic assessment.

Table 11.25: Summary of Contingent Resources in Oil Equivalent Barrels as of 1 January 2021

RPS did not perform commercial evaluation on Contingent Resources.

12 REGIONAL AND HSE RISK ASSESSMENT

Hibiscus has completed a Red Flag review of HSSE performance for the assets included in the transaction. The report is included here (Section 12) for reference.

12.1 Introduction

A Red Flag review was conducted on the HSSE performance of the package of assets that are to be divested by Repsol, S.A. via the potential sale of Fortuna International Petroleum Corporation which holds a 100% interest in each of the following entities (the "Proposed Transaction"):

No.	Entities	Interest (%)*	Block
a.	Repsol Oil & Gas Malaysia Limited	12.7	PM3 CAA
b.	Repsol Oil & Gas Malaysia (PM3) Limited	22.3	PM3 CAA
		60.0	PM305 & PM314 each
		60.0	Kinabalu
c.	Talisman Vietnam Limited	70.0	Block 46 (Cai Nuoc)

**For Repsol's business in Malaysia*

Table 12.1: Repsol Working Interests

Repsol Oil & Gas Malaysia Limited and Repsol Oil & Gas Malaysia (PM3) Limited, ("Repsol") are the Production Sharing Contractors to PETRONAS for the exploration and production of oil and gas offshore Peninsular and East Malaysia.

A specialised HSSE team ("team") was established to identify if the HSSE guidelines, systems and performance have been established and maintained to an adequate standard thereby ensuring that the risks of acquiring the assets were acceptable.

The team had access to a VDR where information regarding the HSSE statistics and other relevant reports/ documents were shared. This enabled the team to identify:

- Potential HSSE issues and/ or HSSE concerns for which further clarifications are required,
- Objectively assess the HSSE risks and associated liabilities from a governance and cost perspective, and
- Identify potential business implications as a result of past, current and future HSSE initiatives and/ or activities.

Based on the available data and responses, the risk of operating Repsol's facilities is assessed as "Medium to High", which is considered normal in the E&P space. Refer to section 5 for the Risk Assessment Matrix.

12.2 HSSE Background

As a PSC holder, Repsol is subjected to the Laws of Malaysia and the terms and condition of the contract entered with PETRONAS. This includes the use of PETRONAS' definition on HSSE management, the adoption of PETRONAS established procedures, reporting of agreed parameters and access by local authorities/ PETRONAS to conduct site inspections and audits.

Three of the important HSSE systems established by PETRONAS and in use by Repsol are:

- PPGUA – PETRONAS Procedures and Guidelines for Upstream Activities
- OSRMS – Offshore Self-Regulatory Management System
- HSEMS – Health Safety Environment Management System

The above three form the operational basis for the conduct of operations and for PETRONAS to inspect and audit upstream operations. Compliance check to the OSRMS (at Tier 3 level) is conducted by a joint team of

PETRONAS and local authorities, while PPGUA compliance check is conducted by PETRONAS through the IOAIA (Integrated Operation Asset Integrity Assurance) and HSEMS audits.

The key focus areas for the team's review are centred around the following, and is based on the HSSE information made available within the VDR:

- HSSE Performance (Statistics)
- HSSE Regulatory Compliance
- HSSE Technical (Operation & Strategic) risks
- Environmental risks
- Overview of the HSSE Services Preparedness & Arrangements (existing contracts, associated Transition/ Operations Costs)

The review covered a period between 2016 through 1Q 2020.

12.3 Executive Summary

The preliminary review of the data in the VDR has enabled the team to identify and assess the primary risks and/ or concerns in the above mentioned key HSSE focus areas.

For the HSSE Performance (Statistics) category, it was observed that the 2019 HSSE Performance Data on the VDR was incomplete and hence a request has been made for the complete data set for our thorough review. A high volume of Near Miss incidents was also observed on an annual basis between 2016 to 1Q 2020 (Note: 2019 data was not available for this incident category). However, on a positive note, 100% completion of work was observed for the execution of HRA, exposure monitoring and health surveillance activities from 2016 to 2019.

A percentage of overdue Safety Corrective Maintenance and Safety Preventive Maintenance works indicate that it is possible to further optimise and improve the overall maintenance strategy. The HSSE Regulatory Compliance review for the assets could not be completed due to the absence of the relevant reports and/ or documents on the VDR.

For the HSSE Technical (Operation & Strategic) risks category, some of the following concern areas were noted (more details are available in section 4.3 below):-

- Presence of CO_2 and Mercury
- Infield pipeline corrosion due to high, wet CO_2
- Not normally present and low levels of H_2S
- Tilting of BRD
- Water treatment & discharge
- Fishermen Encroachment trends are not abnormal
- Presence of foreign enforcement agency vessels, if any, due to the proximity of PM3 CAA & Block 46 to International borders for Right of Way Survey is acknowledged.
- Key HSSE reports (HSEMS audit reports, Tier 3 OSRMS report and the IOAIA audit report) were not available in the VDR
- The complete action item status (includes the RAP) for all safety studies was not available in the VDR.

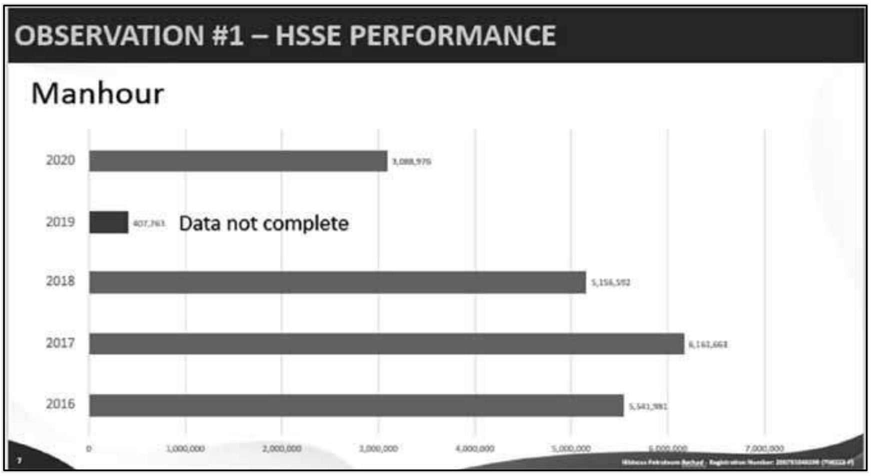
Key observations in the Environmental risks category includes the assessment that all the facilities require marine water monitoring and macrobenthos monitoring. As such, information on the frequency and status of reports submission to DOE as well as the past, current performance and future trending will need to be observed and has been deemed crucial.

Based on the available documentation and queries, Repsol's facilities has been maintained to manage the risk to As Low As Reasonably Practicable (ALARP) which is a benchmark of any Oil & Gas operating asset. The handover of this this asset together with their existing knowledge and experience should be a normal transition with proper management controls in place.

12.4 Findings and Concerns

12.4.1 HSSE Performance (Statistics)

Repsol's HSSE performance for both the leading and lagging HSSE indicators from 2016 to 1Q 2020 are as summarised below (Figure 12.1 to Figure 12.5).



**Note: 2019 HSSE Performance data in the VDR is incomplete. A request has been made for the complete data set.*

Figure 12.1: HSSE Performance – Man hours

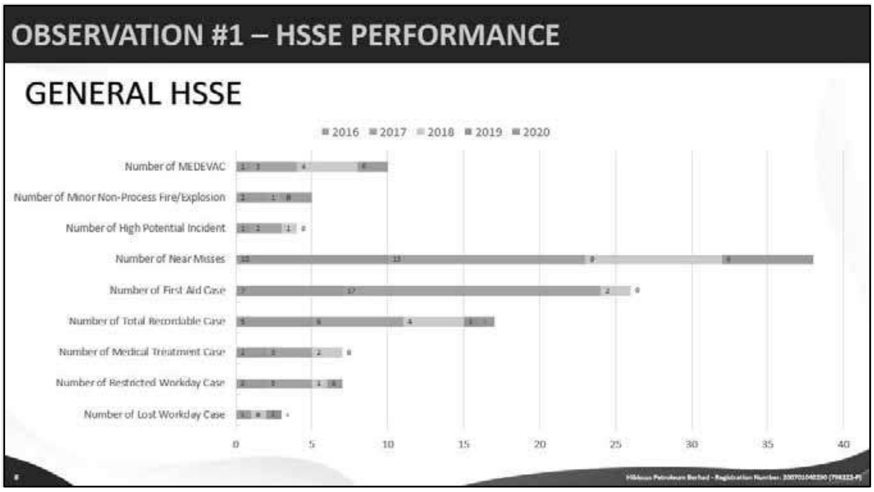


Figure 12.2: HSSE Performance – General HSSE

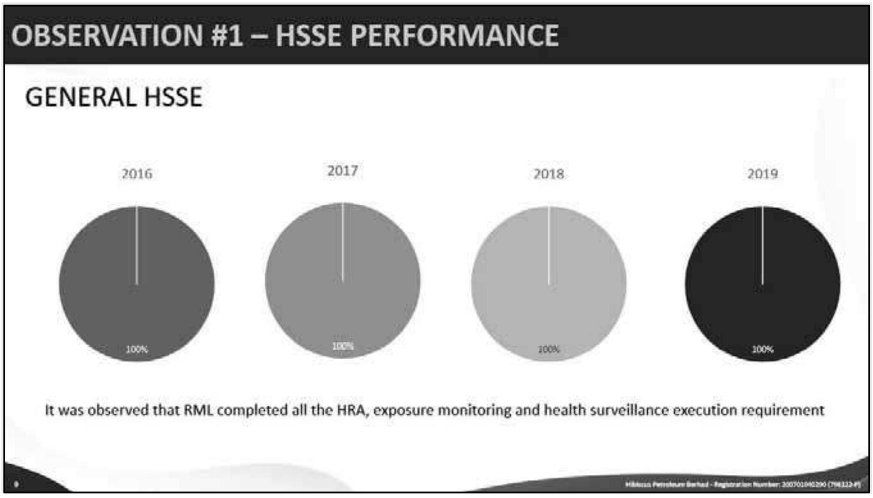


Figure 12.3: HSSE Performance – General HSSE

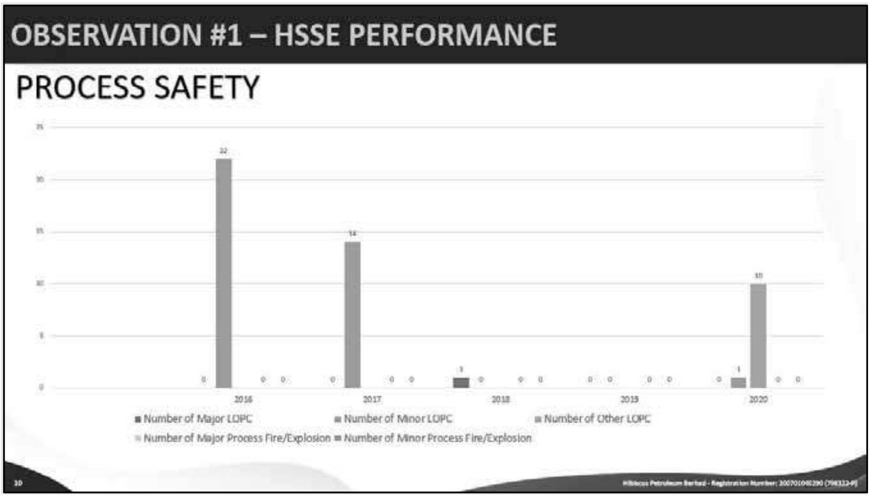


Figure 12.4: HSSE Performance – Process Safety

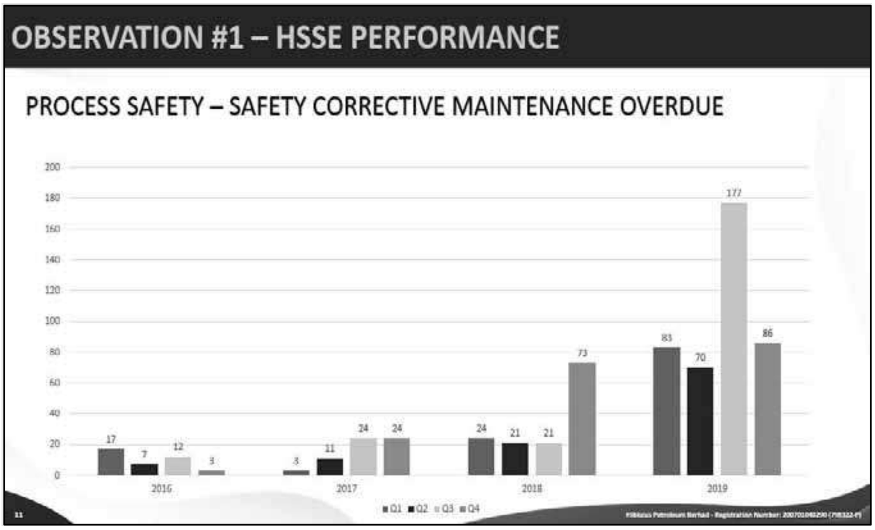


Figure 12.5: HSSE Performance – Process Safety – Safety Corrective Maintenance Overdue

In 4Q 2018 and 1Q & 2Q 2019, more than 20% of Safety Corrective Maintenance works was observed to be overdue (Figure 12.6).

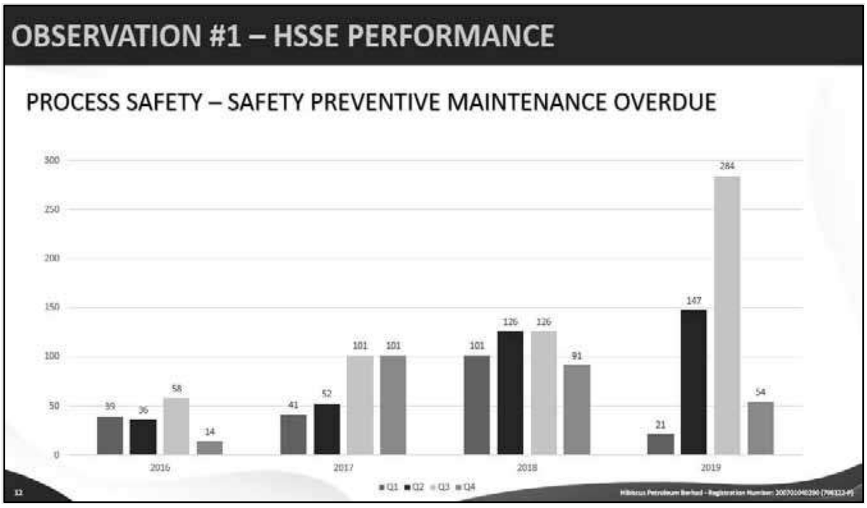


Figure 12.6: HSSE Performance – Process Safety – Safety Preventive Maintenance Overdue

In 1Q 2019, more than 20% of overdue Safety Preventive Maintenance works was observed. The backlog in 2018 and 2019 is due to the issue with PM sign off when moving CMMS from Maximo to SAP. Based on recent IOM report (4Q 2020), the inspection and maintenance program are adhered to, and all the YTD planned activities are being completed. There are some activities deferred due to MCO such as the insulated piping inspection but the overall impact is not significant.

12.4.2 HSSE Regulatory Compliance

The health of the HSSE Regulatory Compliance for the assets was unable to be determined due to the absence of the relevant reports and/ or documents in the VDR.

12.4.3 HSSE Technical (Operation & Strategic) Risks

Several HSSE technical risks and concerns have been ascertained for the Kinabalu and PM3 assets, as listed below:

Kinabalu

i. Not normally present and low levels of H2S

ii. Water treatment & discharge and the impact on the FTSE Sustainability category.

iii. Based on a QRA study dated 2017, there is a requirement to provide a lifeboat at KNDPA PMP.

iv. Fire rating of fire-proof coating is required as per the HSE case.

v. Key HSSE reports (HSEMS audit reports, Tier 3 OSRMS report and the IOAIA audit report) were not made available in the VDR.

vi. The complete action item status (includes the RAP) for all safety studies was not available in the VDR.

PM3

i. CO2 issues (Large impact to the group GHG emission reporting that could adversely affect stakeholder sentiments).

ii. Infield pipeline corrosion due to high, wet CO2 (within the Operational controls).

iii. Mercury issues (Managed within the Operational controls).

iv. Water treatment & discharge (Impact to the FTSE Sustainability category of total water discharge).

v. Tilting of BRD (High risk repair works involving underwater contractors).

vii. Key HSSE reports (HSEMS audit reports, Tier 3 OSRMS report and the IOAIA audit report) was not available on the VDR.

viii. The complete action item status (includes the RAP) for all safety studies was not available on the VDR.

PM3 N

I. It was mentioned within the PM3N Operations HSE case that the P&ID was not updated as it does not reflect the actual (at that point in time) equipment configuration and arrangements i.e. open and closed drain system for BO-A, BO-B, BO-C and BO-D.

II. The emergency drill philosophy is not met, PM3 N conducts bi-weekly drills - However, based on the ERP, the tactical response team capability should be tested on weekly basis.

III. Status of relocation of life raft - The current life raft is not placed at strategic place and it was recommended that the life raft be relocated to a protected utility area.

Although there is data gap for Security and Encroachment incidents, the prevalent data for the East Coast of Peninsular Malaysia is primarily on fishing encroachment within the 500m zone. Fishing encroachments within the Kinabalu field is similar to the current trend of security encroachments that are being observed in North Sabah. Presence of foreign enforcement agency vessels, if any, due to the proximity of PM3 CAA & Block 46 to International borders for Right of Way Survey is acknowledged.

12.4.4 Environmental Risks

Table 12.2 below shows the summary existing environment requirements by DOE for all facilities (based on information available on the VDR pertaining to the EIA Approval Conditions).

<table>
<tr><th>Facility</th><th>Date of Approval</th><th>Requirement</th><th>Frequency</th><th>Remarks
(HSSE - Hibiscus)</th></tr>
<tr><td colspan="5">1 – Kinabalu Platform Debottlenecking Project</td></tr>
<tr><td rowspan="7">Kinabalu Platform Debottlenecking Project</td><td rowspan="7">29 May 2019</td><td>EIA-2-18 submission</td><td>Quarterly</td><td>Submission info/ reports not sighted</td></tr>
<tr><td>Marine water and macrobenthos monitoring</td><td>6-monthly

Approval by DOE through IEMP dated 10 Dec 2019 has been reduced to annually</td><td>To check whether contract for this scope includes vessel</td></tr>
<tr><td>Marine water and macrobenthos monitoring Report submission to DOE</td><td>6-monthly

Approval by DOE through IEMP dated 10 Dec 2019 has been reduced to annually</td><td>Detailed info/ Submission reports not sighted</td></tr>
<tr><td>Produced water (OIW) – below 100 mg/l</td><td>Continuous</td><td>Submission reports not sighted</td></tr>
<tr><td>EMP</td><td>Submitted and approved</td><td>Approved by DOE on 10 Dec 2019
- Detailed info not sighted</td></tr>
<tr><td>Environmental Audit</td><td>Annual</td><td>Detailed info/ Submission reports not sighted</td></tr>
<tr><td>GSR / Emains</td><td>Continuous</td><td>Submission reports not sighted</td></tr>
<tr><td colspan="5">2 – PM3 – Bunga Tulip Field Development, PM-3 Commercial Arrangement Area, EEZ</td></tr>
<tr><td rowspan="3">PM3 – Bunga Tulip Field Development, PM-3 Commercial Arrangement Area, EEZ</td><td rowspan="3">10 August 2006</td><td>Marine water and macrobenthos monitoring</td><td>Information not sighted</td><td>Detailed info/ Submission reports not sighted</td></tr>
<tr><td>EIA-2-18</td><td>Quarterly</td><td>Submission info/ reports not sighted</td></tr>
<tr><td>EMP for PM3 CAA Development, Offshore Malaysia, South China Sea</td><td>Information not sighted</td><td>Approved by DOE 17 Nov 2015
- Detailed info not sighted</td></tr>
<tr><td colspan="5">3 – Bunga Orkid - Northern Fields Development, PM-3 Commercial Arrangement Area, EEZ</td></tr>
<tr><td rowspan="4">Bunga Orkid - Northern Fields Development, PM-3 Commercial Arrangement Area, EEZ</td><td rowspan="4">10 June 2007</td><td>Produced water (OIW) – 100mg/l</td><td>Quarterly</td><td>Submission reports not sighted</td></tr>
<tr><td>EIA-2-18</td><td>Quarterly</td><td>Submission info/ reports not sighted</td></tr>
<tr><td>Marine water and macrobenthos monitoring</td><td>Information not sighted</td><td>Detailed info/ Submission reports not sighted</td></tr>
<tr><td>EMP for PM3 CAA Development, Offshore Malaysia, South China Sea</td><td>Information not sighted</td><td>Approved by DOE 17 Nov 2015
- Detailed info not sighted</td></tr>
</table>

Facility	Date of Approval	Requirement	Frequency	Remarks (HSSE - Hibiscus)
Bunga Orkid (MRU) – EIA Supplementary for Northern Fields Development Project – BO-A CPP (Mercury Removal Unit-MRU)	8 February 2010	EIA-2-18	Quarterly	Submission reports not sighted
4 – Blok PM-3 Kawasan Kerjasama Komersial				
Blok PM-3 Kawasan Kerjasama Komersial	9 April 2003	Marine water monitoring	Quarterly	Detailed info/ Submission reports not sighted
		Macrobenthos monitoring	Information not sighted	Detailed info/ Submission reports not sighted
		Marine water monitoring report submission to DOE	Quarterly	Detailed info/ Submission reports not sighted
		Produced water (OIW) – 100 mg/l	Continuous	Submission reports not sighted
		EMP for PM3 CAA Development, Offshore Malaysia, South China Sea	Information not sighted	Approved by DOE 17 Nov 2015 - Detailed info not sighted
5 – Bunga Pakma Filed Development, Block PM-3, Offshore Kelantan				
Bunga Pakma Filed Development, Block PM-3, Offshore Kelantan	9 September 2014	EIA-2-18	Quarterly	Submission info/ reports not sighted
		Produced water (OIW) – 100 mg/l reporting	Quarterly	Submission reports not sighted
		Air emission monitoring - NO2, CO2, TPM	Periodic with CAR 2014 limit	CAR 2014 is not applicable in offshore
		Macrobenthos monitoring	Information not sighted	Detailed info/ Submission reports not sighted
		EMP for PM3 CAA Development, Offshore Malaysia, South China Sea	Information not sighted	Approved by DOE 17 Nov 2015 - Detailed info not sighted
6 – Bunga Kekwa – PM-3 Block – EIA Revision 2				
Bunga Kekwa – PM-3 Block – EIA Revision 2	4 January 2000	Produced water (OIW) – 100 mg/l	Continuous	Submission reports not sighted
		EMP for PM3 CAA Development, Offshore Malaysia, South China Sea	Information not sighted	Approved by DOE 17 Nov 2015 - Detailed info not sighted

Facility	Date of Approval	Requirement	Frequency	Remarks (HSSE - Hibiscus)
7 – South Angsi Development, Block PM-305, EEZ				
South Angsi Development, Block PM-305, EEZ	4 October 2014	Produced water (OIW) – 100 mg/l reporting	Quarterly	Submission reports not sighted
		EMP	Submitted 5 July 2017	Approved on 10 July 2017 - Detailed info not sighted
		Macrobenthos monitoring	Information not sighted	Detailed info/ Submission reports not sighted
		EIA-2-18	Quarterly	Submission info/ reports not sighted

Table 12.2: Summary Existing Environmental Requirements by DOE for All Facilities

As all the facilities require marine water monitoring and macrobenthos monitoring, information on their frequency and status of the report submission(s) to DOE is crucial. Detailed information on number of marine water sampling points, its depth, number of sampling points for sediment, the parameters and frequency as well as past, current performance and future trending will need to be observed.

There are uncertainties on whether the EIA-2-18 forms were submitted to DOE for all the facilities above. This submission is very crucial in order to demonstrate compliance to the Environmental requirements and as a checklist for all the activities required in the Approval Conditions.

12.4.5 GHG Emissions

The few projects of GHG emission reduction as presented in the first session are example of the commitment to reduce certain amount of the GHG emission. The commitment further showed in the company as it is the signatory member of MGP - Methane Guiding Principles as a volunteer under international multi-stakeholder partnership between industry and non-industry organisations working to reduce methane emissions along the entire natural gas value chain.

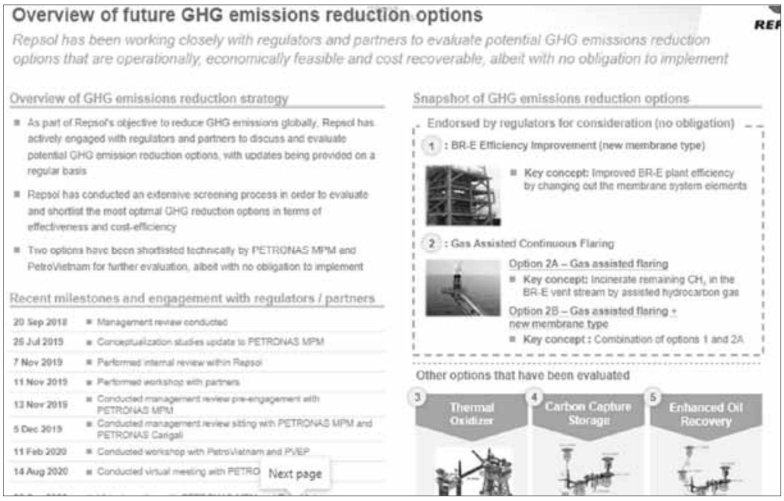


Figure 12.7: GHG Emission Reduction Project Options

Graphic above shows the snapshot of 5 GHG Emission Reduction Project Options (Figure 12.7).

Although the Government of Malaysia does not have any commitment to net zero emissions reduction target by 2050, PETRONAS has declared their aspiration to achieve this goal. In line with PETRONAS aspiration and REPSOL's net zero target by 2050, Hibiscus Petroleum Bhd aspires to achieve the same climate goal set forth by both PETRONAS and Repsol.

In that regard, this report covers the baseline of GHG emissions and the carbon intensity from Repsol's Malaysian asset from 2021 to 2032 and the mitigation measures proposed including the investment cost to achieve the emission reduction.

Aggregated Asset (2020-2027):

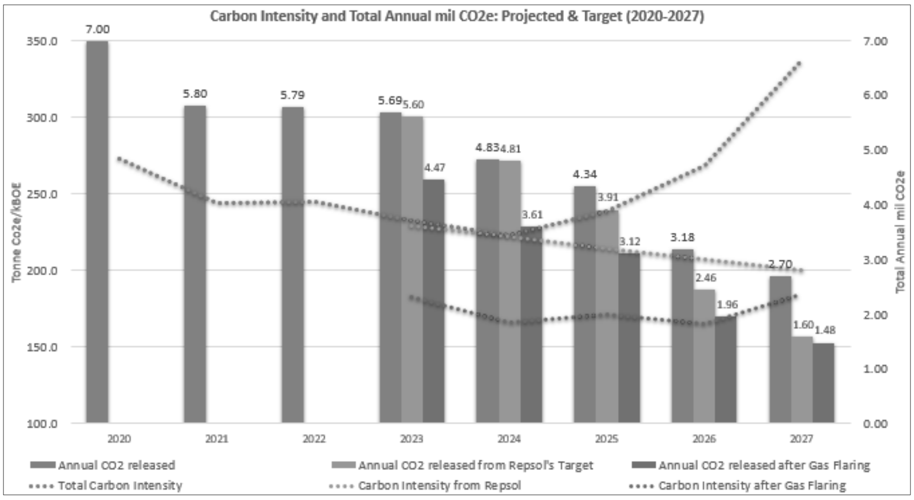


Figure 12.8: Aggregated Asset (2020 – 2027)

The forecasted annual CO2 released in red forms the baseline (source: WP&B). The Carbon Intensity increases from the year 2024 onward as the forecasted GHG emissions are flat whereas the total production is decreasing annually.

Kinabalu Asset (2028 – 2032)

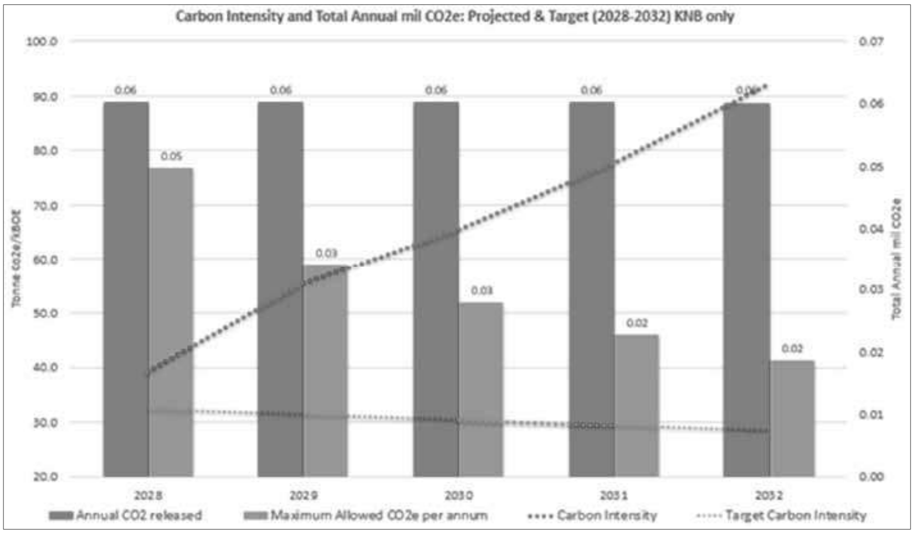
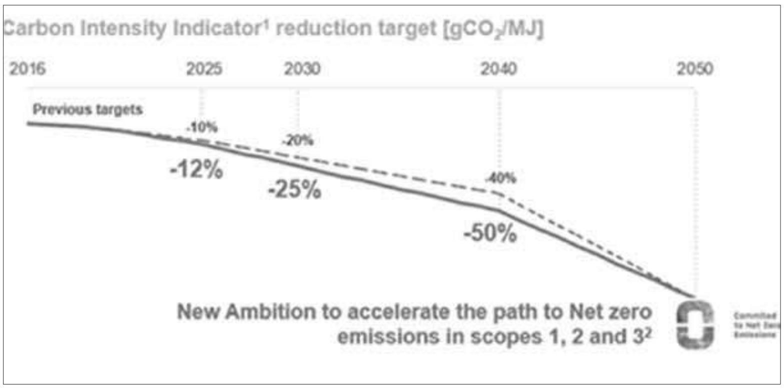


Figure 12.9: Kinabalu Asset (2028 – 2032)

Post 2027, PM3 PSC will expire and the above chart focuses only on Kinabalu asset:

The forecasted annual CO2 released in red forms the baseline; The Carbon Intensity increases from the year 2028 onward as the forecasted GHG emissions are flat whereas the total production is decreasing annually.

Forest Carbon Offset is proposed as a mitigation factor for PM3. The amount of offset is based on Repsol's Global Emission Reduction Target (Figure 12.10) denoted in green. Repsol's reduction is based on 2016 as base year but in our case, 2021 was used as base year as 2016 data is not available and 2021 carbon intensity was lower than 2020. A lower emission base year was chosen to reflect Hibiscus' aspiration to reduce CO2 emission further.



Source: https://www.repsol.com/en/press-room/press-releases/2020/repsols-new-strategic-plan-accelerates-the-energy-transition.cshtml

Figure 12.10: Repsol's Global Emission Reduction Target

Total estimated investment in forest carbon offset is US$ 12 million to US$ 32 million (based on US$ 5/tonne CO2e[i] and US$ 13.9/tonne CO2e respectively[ii]). Gas Assisted Flaring as proposed by Repsol – in blue (total cost is US$ 16 million covering Capex and Opex)

There are still uncertainties regarding the factors used to calculate the AGRU CO2 emissions for PM3. These will be cleared up later in the process.

Mitigation measure proposed for Kinabalu are:

1. Forest Carbon Offset
   - The amount of offset is again based on Repsol's Global Emission Reduction Target (denoted in green);
   - The base year for carbon intensity for Kinabalu is based on 2021 to maintain consistency with reduction efforts up to 2027 (combined PM3 & KN);
   - Total estimated cost is US$750,000 – US$ 2 million based on US$ 5/tonne CO2e and US$13.9/tonne CO2e respectively)
2. Gas debottlenecking (Figure 12.11). This is not currently included as a GHG emission mitigation measure as the investment cost is not known. Nevertheless, there is a reduction of 64,000 tonnes CO2e for the deploying year which translates to reduction of 2tonnes CO2e/Mboe in carbon intensity for Kinabalu.

COMPETENT PERSON'S REPORT IN RELATION TO THE RESERVES AND RESOURCES EVALUATION OF THE ASSETS (CONT'D)

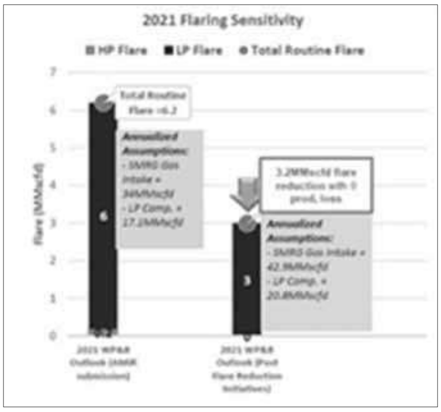


Figure 12.11: Gas Debottlenecking

[i] *KeTSA's REDD+ Financing Framework, proposal of US$5/tonne CO2e*

[ii] *https://www.forestcarbon.co.uk/single-credits*

It is also important to know Repsol's level of compliance to the new MPM issued Guideline on PETRONAS Exploration & Production Minimum Expectation on Scheduled Wastes Management for Offshore Operators, Oct 2019.

Projects focusing on renewable energy initiatives on site i.e. installation and utilisation of solar panels and wind turbines are a bonus and demonstrates the commitment towards PETRONAS 2050 net zero emission target.

Currently, information on the presence of a mini laboratory offshore is being sought as this could be a potential issue during an external audit with the certification body.

12.5 Conclusions

Based on the available documentation and queries, Repsol's facilities has been maintained to manage the risk to As Low As Reasonably Practicable (ALARP) which is a benchmark of any Oil & Gas operating asset. The handover of this this asset together with their existing knowledge and experience should be a normal transition with management controls.

Using Hibiscus's risk matrix (Table 12.3 and Table 12.4), the Hibiscus HSSE personnel have assessed the risk of operating Repsol's facilities in the yellow and amber band which is typical of any Oil & Gas operating asset.

a. GHG – PETRONAS target of Zero Emission by 2050. It is noted that five GHG emission reduction project options were evaluated and two projects (BR-E Efficiency Improvement (new membrane type) & Gas Assisted Continuous Flaring) have been endorsed by the regulators for consideration with no obligation at this juncture. In line with PETRONAS aspiration and REPSOL's net zero target by 2050, Hibiscus Petroleum Bhd aspires to achieve the same climate goal set forth by both PETRONAS and Repsol. Therefore, for Aggregated Asset, two mitigation measures have been proposed. They are Forest Carbon Offset and Gas Assisted Flaring as proposed by Repsol. For Kinabalu, mitigation measure proposed is Forest Carbon Offset (4C)

b. Mercury - Mercury in the form produced at PM3 or any other producing field in the Thai Basin is elemental mercury and mercury salts, which if present can build up in the body in the event of excessive exposure and create illness. Thus, moderate impact of occupational health illness is expected in the event of an exposure. However, this is a lower probability event due to Operational controls (3B).

c. SCPM & SCCM – Backlog of overdue maintenance diminishes the Asset Integrity with more physical components working beyond safe operating limits with the potential catastrophic severity. However, the implementation of any reasonable design and maintained facility will manage the probability to a very unlikely level (5A).

d. Presence of foreign enforcement agency vessels, if any, due to the proximity of PM3 CAA & Block 46 to International borders for Right of Way Survey is acknowledged. (5A).

Consequences					Probability				
Severity	People	Asset/Financial	Environment	Reputation	A (1) Very unlikely	B (2) Unlikely	C (3) Possible	D (4) Likely	E (5) Almost certain
5 Catastrophic	Multiple Fatalities	**Massive Damage** Financial loss >USD50 million. Event likely to lead to bankruptcy of HPB	**Massive Effect** Permanent impact on highly valued ecosystems, species or habitat	**Massive international consequence** International public attention. Extensive adverse attention in international media. Mandate to operate revoked	C 5 D	10	15	20	25
4 Major	Single Fatality **PTD, PPD**	**Major Damage** Financial loss >USD10-USD50 million	**Major Effect** Major long term (>5years) impact on ecosystems, species or habitat	**Major national consequence** National public concern. Extensive adverse attention in the national media. Mandate to operate restricted	4	8	A 12	16	20
3 Moderate	**Major injury or health effect** LTI or temporary disability	**Moderate Damage** Financial loss >USD5-USD10 million	**Moderate Effect** Limited environmental damage. Moderate medium term (2-5 years) impact but not affecting ecosystem function	**Moderate localised consequence** National media and/or regional regulatory attention resulting in negative consequence on company operations	3	B 6	9	12	15
2 Minor	**Minor injury or health effect** MTC or RWC	**Minor Damage** Financial loss >USD0.5-USD5 million	**Minor Effect** Minor short term (1-2 years) environmental damage, but no lasting effect.	**Limited consequence** Local media and/or local regulatory attention with limited negative consequence for company operations	2	4	6	8	10
1 Slight	**Slight injury or health effect** No Treatment Case or FAC	**Slight Damage** Financial loss <USD0.5 million	**Slight Effect** Slight and temporary (<1 year) environmental damage localized effect on ecosystem, species or habitat	**Slight effect** Local public awareness but no discernible concern.	1	2	3	4	5
Notes:	PTD: Permanent Total Disability PPD: Partial Permanent Disability LTI: Lost Time Injury MTC: Medical Treatment Case RWC: Restricted Work Case FAC: First Aid Case See explanation table	Direct Cost: Costs attributable to the incident including loss of revenue, repair or restoration costs See explanation table	See explanation table	See explanation table	Theoretically possible but not occurred yet in the industry (not in last 100 years)	Has occurred in the industry (once or twice in last 10 years)	Has occurred once within HPB or many times in the industry (last 5 years)	Could occur in most circumstances in the industry (once per year)	Expected to occur in most circumstances in the industry (multiple occurrences in a year)

Table 12.3: Hibiscus Risk Assessment Matrix

Consequences	
Risk rating	Intervention
16-25	Risk is not tolerable. - Mitigate the Risk by incorporation of control and recovery action(s) to reduce the Risk rating to HIGH or below Incidents and Assurance findings/reports reportable to Group CEO Incident investigation led by Op Co CEO or delegate. Hi Po incident investigation led by Op Co L2
9-15	Risk is tolerable if supported by ALARP demonstration - Undertake risk reduction by applying appropriate control and recovery barriers - Review and approval of ALARP demonstration by Op Co L3 Incidents and Assurance findings/reports reportable to Op Co CEO Incident investigation led by Op Co L3
4-8	Risk is tolerable if supported by ALARP demonstration - Undertake control evaluation - Review and approval of ALARP demonstration by HOD / Op Co L4 - Monitor using procedure or appropriate internal control Incidents and Assurance findings/reports reportable to Op Co L3 Incident investigation led by Op Co L4
1-3	Risk is tolerable - Monitor at operational level using procedure/appropriate internal control - Take corrective action according to availability of resources

Table 12.4: Risk Rating and Required Intervention

The Transition should be a continuation of existing work practices encompassing all the safety critical elements and controls. This strategy aims to not only enable a smooth Transition phase but also to minimise the introduction of new risks to personnel on Day 1.

The development of Hibiscus bridging documents, where necessary, will be managed at the Transition phase accordingly after a detailed gap assessment exercise. However, the project to structure the alignment of the existing Repsol manuals, plans, and procedures to that of Hibiscus' Risk Control Framework will be managed thereafter upon Completion on a staggered timeline approach.

13 CONSULTANT'S INFORMATION

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The evaluation presented in this report reflects our informed judgment, based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of Reserves and Resources are based on data provided by Repsol and J.P. Morgan. We have accepted, without independent verification, the accuracy and completeness of this data.

The report represents RPS' best professional judgment and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving future performance and development activities may be subject to significant variations over short periods of time as new information becomes available. This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety. This report was provided for the sole use of Hibiscus. The provision of professional services has been solely on a fee basis.

To the best of our knowledge, no conflict of interest has existed in the work conducted as part of this report. Furthermore, RPS nor any of the management and employees involved in the work have any interest in the assets evaluated or related to the analysis carried out as part of this report.

Mr Jim Bradly, Operations Director - EAME, has supervised this evaluation. Mr Bradly is a Chartered Engineer, Chartered Petroleum Engineer and member of the Energy Institute in the UK with over 20 years' experience in upstream oil and gas and 15 years' experience in the evaluation of oil and gas Reserves and Resources.

Table 13.1 provides a summary of staff involved in this evaluation, their level of experience and professional qualifications.

Name	Role	Years of Experience	Qualifications	Professional Memberships
Jim Bradly	Supervisor and Reservoir Engineering Lead	>20	MSc. Petroleum Engineering, Imperial College, London, 2004 BEng Electronic and Electrical Engineering, Manchester University (1993-1996)	CEng MEI Chartered Petroleum Engineer (Registration # 569021) Member, Energy Institute Member, AIPN Member, SPE Member, SPWLA
David Offer	Geology Lead	26	2018 Qualified Teacher Status: Department of Education, Her Majesty's Government of the United Kingdom of Great Britain and Northern Ireland. • 1995 M.Sc. Industrial Minerology, University of Leicester • 1994 B.Sc. (Hons). Exploration and Mining Geology. University of Wales, College of Cardiff.	Fellow Geological Society of London Vice President of the Petroleum Exploration Society of Great Britain (PESGB)
Gordon Fraser	Cost Engineering Lead	>35	MBA, University of Glasgow BSc, Fuel and Energy Engineering, University of Leeds	
Joseph Tan	Project Manager/Economics Lead	20	B.Eng. (Hons.) Petroleum Engineering, Universiti Teknologi Malaysia, 2001	Member – Society of Petroleum Engineers (SPE) Member – South East Asia Petroleum Exploration Society (SEAPEX) Member – Association of International Petroleum Negotiators (AIPN)

Table 13.1: Summary of Summary of Lead Consultant Personnel

14 DATA SOURCES

The data for this report was provided in both virtual data room and physical data rooms hosted by Repsol in their Malaysian offices, accessible via MS Teams or Intralinks web portals.

Appendix A
Glossary

1C	The low estimate of Contingent Resources. There is estimated to be a 90% probability that the quantities actually recovered could equal or exceed this estimate
2C	The best estimate of Contingent Resources. There is estimated to be a 50% probability that the quantities actually recovered could equal or exceed this estimate
3C	The high estimate of Contingent Resources. There is estimated to be a 10% probability that the quantities actually recovered could equal or exceed this estimate
1P	The low estimate of Reserves (proved). There is estimated to be a 90% probability that the quantities remaining to be recovered will equal or exceed this estimate
2P	The best estimate of Reserves (proved+probable). There is estimated to be a 50% probability that the quantities remaining to be recovered will equal or exceed this estimate
3P	The high estimate of Reserves (proved+probable+possible). There is estimated to be a 10% probability that the quantities remaining to be recovered will equal or exceed this estimate
1U	The unrisked low estimate of Prospective Resources
2U	The unrisked best estimate of Prospective Resources
3U	The unrisked high estimate of Prospective Resources
AVO	Amplitude versus Offset
B	Billion
bbl(s)	Barrels
bbls/d	Barrels per day
Bcm	Billion cubic metres
B_g	Gas formation volume factor
B_{gi}	Gas formation volume factor (initial)
B_o	Oil formation volume factor
B_{oi}	Oil formation volume factor (initial)
B_w	Water volume factor
boe	Barrels of oil equivalent
stb/d	Barrels of oil per day
BHP	Bottom hole pressure
Bscf	Billions of standard cubic feet
bwpd	Barrels of water per day
condensate	A mixture of hydrocarbons which exist in gaseous phase at reservoir conditions but are produced as a liquid at surface conditions
cP	Centipoise
Eclipse	A reservoir modelling software package
E_{gi}	Gas Expansion Factor
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
FBHP	Flowing bottom hole pressure
FTHP	Flowing tubing head pressure
ft	Feet
FWHP	Flowing well head pressure
FWL	Free Water Level
GDT	Gas Down To

GIIP	Gas Initially in Place
GOC	Gas oil Contact
GOR	Gas/oil ratio
GRV	Gross rock volume
GWC	Gas water contact
IPR	Inflow performance relationship
IRR	Internal rate of return
KB	Kelly Bushing
k_a	Absolute permeability
k_h	Horizontal permeability
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	Cubic metres
m^3/d	Cubic metres per day
ma	Million years
M	Thousand
M$	Thousand US dollars
MBAL	Material balance software
Mbbls	Thousand barrels
mD	Permeability in millidarcies
MD	Measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMbbls	Million barrels
MMscf/d	Millions of standard cubic feet per day
MMstb	Million stock tank barrels (at 14.7 psi and 60° F)
MMt	Millions of tonnes
MM$	Million US dollars
MPa	Mega pascals
m/s	Metres per second
msec	Milliseconds
Mt	Thousands of tonnes
mV	Millivolts
NTG or N:G	Net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	Oil water contact
P90	There is estimated to be at least a 90% probability (P_{90}) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P_{50}) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P_{10}) that this quantity will equal or exceed this high estimate
PDR	Physical data room
Petrel™	A geoscience and reservoir engineering software package
petroleum	Naturally occurring mixtures of hydrocarbons which are found beneath the Earth's surface in liquid, solid or gaseous form

phi	Porosity
p_i	Initial reservoir pressure
PI	Productivity index
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch (absolute)
psig	Pounds per square inch (gauge)
p_{wf}	Flowing bottom hole pressure
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	Pressure volume temperature
rb	Barrel(s) at reservoir conditions
rcf	Reservoir cubic feet
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	Repeat formation tester
RKB	Relative to kelly bushing
rm^3	Reservoir cubic metres
SCADA	Supervisory control and data acquisition
SCAL	Special Core Analysis
scf	Standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	Standard cubic feet per day
scf/stb	Standard cubic feet per stock tank barrel
SGS	Sequential Gaussion Simulation
SIBHP	Shut in bottom hole pressure
SIS	Sequential Indicator Simulation
sm^3	Standard cubic metres
S_o	Oil saturation
S_{oi}	Initial oil saturation
S_{or}	Residual oil saturation
S_{orw}	Residual oil saturation relative to water
sq. km	Square kilometers
stb	Stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	Stock tank barrels per day
STOIIP	Stock tank oil initially in place
S_w	Water saturation
S_{wc}	Vonnate water saturation
$	United States Dollars
t	Tonnes
THP	Tubing head pressure
Tscf	Trillion standard cubic feet
TVDSS	True vertical depth (sub-sea)
TVT	True vertical thickness
TWT	Two-way time
US$	United States Dollar
VDR	Virtual data room
VLP	Vertical lift performance

V_{sh}	Shale volume
VSP	Vertical Seismic Profile
W/m/K	Watts/metre/° K
WC	Water cut
WUT	Water Up To
Z	A measure of the "non-idealness" of gas
ϕ	Porosity
μ	Viscosity
μ_g	Viscosity of gas
μ_o	Viscosity of oil
μ_w	Viscosity of water

Appendix B
Summary of Reporting Guidelines

PRMS is a fully integrated system that provides the basis for classification and categorization of all petroleum reserves and resources.

B.1 Basic Principles and Definitions

A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. Quantities of petroleum and associated products can be reported in terms of volumes (e.g., barrels or cubic meters), mass (e.g., metric tonnes) or energy (e.g., Btu or Joule). These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

B.1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

Figure A.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

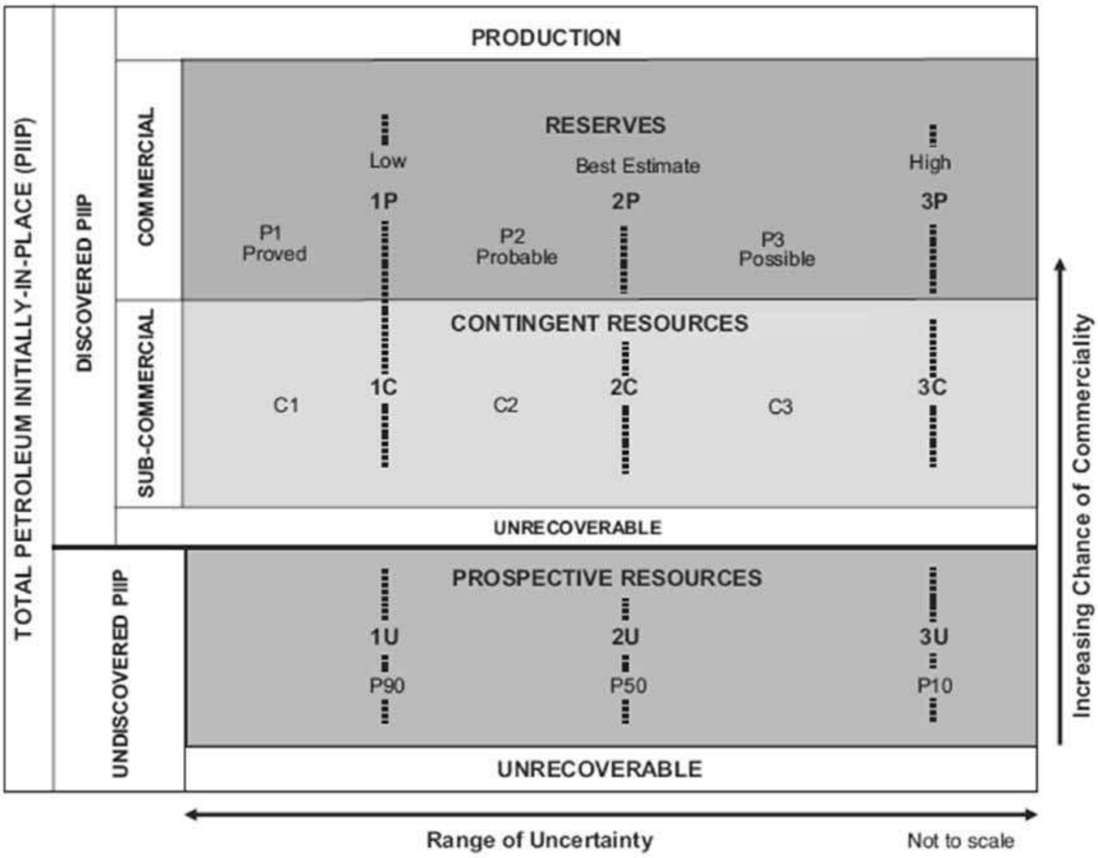


Figure A.1: Resources classification framework

The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

The following definitions apply to the major subdivisions within the resources classification:

- **Total Petroleum Initially-In-Place (PIIP)** is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
- **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.
- **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see PRMS 2018 Section 3.2, Production Measurement).

Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

- **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see PRMS 2018 Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

- **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub- classified based on project maturity and/or economic status.
- **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
- **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.
- **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

Other terms used in resource assessments include the following:

- **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
- **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

Whenever these terms are used, the conditions associated with their usage must be clearly noted and documented.

B.1.2 Project Based Resource Evaluations

The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure A.2).

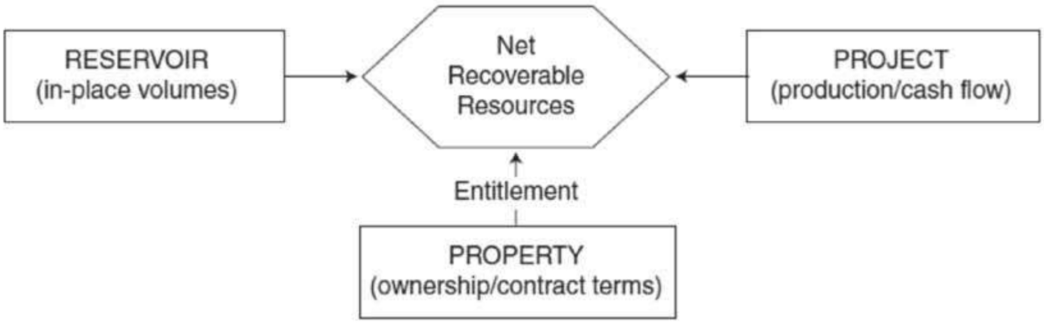


Figure A.2: Resources Evaluation

The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty.

The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See PRMS 2018 Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See PRMS 2018 Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously. When multiple options for development exist early in project maturity, these options should be reflected as competing project alternatives to avoid double counting until decisions further refine the project scope and timing. Once the scope is described and the timing of decisions on future activities established, the decision steps will generally align with the project's classification. To assign recoverable resources of any class, a project's development plan, with detail that supports the resource commercial classification claimed, is needed.

The estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. In-place quantities for which a feasible project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see PRMS 2018 Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see PRMS 2018 Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).

The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

B.2 Classification and Categorization Guidelines

To consistently characterize petroleum projects, evaluations of all resources should be conducted in the context of the full classification system shown in Figure A.1. These guidelines reference this classification system and support an evaluation in which projects are "classified" based on their chance of commerciality, P_c (the vertical axis labeled Chance of Commerciality), and estimates of recoverable and marketable quantities associated with each project are "categorized" to reflect uncertainty (the horizontal axis). The actual workflow of classification versus categorization varies with individual projects and is often an iterative analysis leading to a final report. Report here refers to the presentation of evaluation results within the entity conducting the assessment and should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.

B.2.1 Resources Classification

The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

B.2.1.1 Determination of Discovery Status

A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see PRMS 2018 Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

Where a discovery has identified recoverable hydrocarbons, but is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

B.2.1.2 Determination of Commerciality

Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see PRMS 2018 Section 3.1.1, Net Cash-Flow Evaluation).
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO_2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the *2P* Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see PRMS 2018 Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section A.2.1.2. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

B.2.1.3 Project Status and Chance of Commerciality

Evaluators have the option to establish a more detailed resources classification reporting system that can also provide the basis for portfolio management by subdividing the chance of commerciality axis according to project maturity. Such sub-classes may be characterized qualitatively by the project maturity level descriptions and associated quantitative chance of reaching commercial status and being placed on production.

As a project moves to a higher level of commercial maturity in the classification (see Figure A.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality, P_c, which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geologic discovery," P_g.
- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," P_d.

There must be a high degree of certainty in the chance of commerciality, P_c, for Reserves to be assigned; for Contingent Resources, $P_c = P_d$; and for Prospective Resources, P_c is the product of P_g and P_d.

Contingent and Prospective Resources can have different project scopes (e.g., well count, development spacing, and facility size) as development uncertainties and project definition mature.

B.2.1.3.1 Project Maturity Sub-classes

As Figure A.3 illustrates, development projects and associated recoverable quantities may be sub- classified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production.

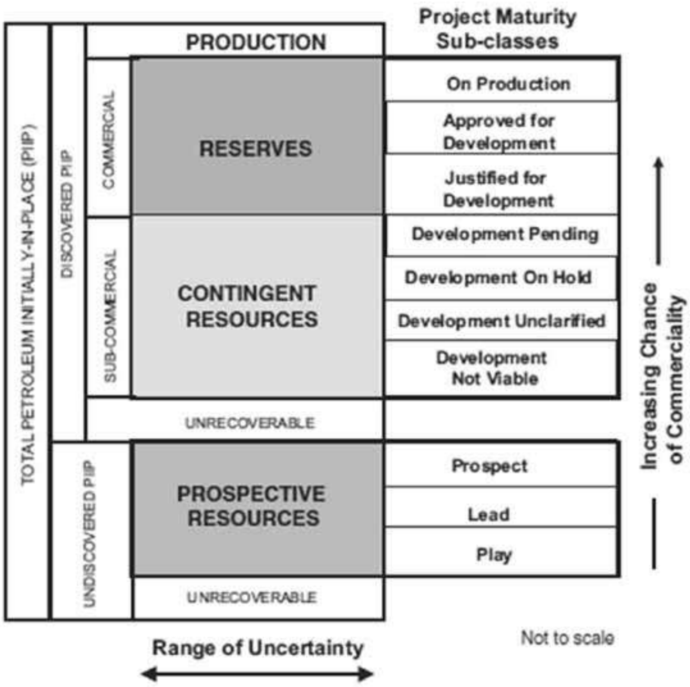


Figure A.3: Sub-classes based on project maturity

Maturity terminology and definitions for each project maturity class and sub-class are provided in PRMS 2018 Table I. This approach supports the management of portfolios of opportunities at various stages of exploration, appraisal, and development. Reserve sub-classes must achieve commerciality while Contingent and Prospective Resources sub-classes may be supplemented by associated quantitative estimates of chance of commerciality to mature.

Resources sub-class maturation is based on those actions that progress a project through final approvals to implementation and initiation of production and product sales. The boundaries between different levels of project maturity are frequently referred to as project "decision gates."

Projects that are classified as Reserves must meet the criteria as listed in Section A.2.1.2, Determination of Commerciality. Projects sub-classified as Justified for Development are agreed upon by the managing entity and partners as commercially viable and have support to advance the project, which includes a firm intent to proceed with development. All participating entities have agreed to the project and there are no known contingencies to the project from any official entity that will have to formally approve the project.

Justified for Development Reserves are reclassified to Approved for Development after a FID has been made. Projects should not remain in the Justified for Development sub-class for extended time periods without positive indications that all required approvals are expected to be obtained without undue delay. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), the project shall be reclassified as Contingent Resources.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

Where commercial factors change and there is a significant risk that a project with Reserves will no longer proceed, the project shall be reclassified as Contingent Resources.

For Contingent Resources, evaluators should focus on gathering data and performing analyses to clarify and then mitigate those key conditions or contingencies that prevent commercial development. Note that the Contingent Resources sub-classes described above and shown in Figure A.3 are recommended; however, entities are at liberty to introduce additional sub-classes that align with project management goals.

For Prospective Resources, potential accumulations may mature from Play, to Lead and then to Prospect based on the ability to identify potentially commercially viable exploration projects. The Prospective Resources are evaluated according to chance of geologic discovery, P_g, and chance of development, P_d, which together determine the chance of commerciality, P_c. Commercially recoverable quantities under appropriate development projects are then estimated. The decision at each exploration phase is whether to undertake further data acquisition and/or studies designed to move the Play through to a drillable Prospect with a project description range commensurate with the Prospective Resources sub-class.

B.2.1.3.2 Reserves Status

Once projects satisfy commercial maturity (criteria given in PRMS 2018 Table 1), the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan (PRMS 2018 Table 2 provides detailed definitions and guidelines):

- **Developed Reserves** are quantities expected to be recovered from existing wells and facilities.
  - **Developed Producing Reserves** are expected to be recovered from completion intervals that are open and producing at the time of the estimate.
  - **Developed Non-Producing Reserves** include shut-in and behind-pipe reserves with minor costs to access.
- **Undeveloped Reserves** are quantities expected to be recovered through future significant investments.

The distinction between the "minor costs to access" Developed Non-Producing Reserves and the "significant investment" needed to develop Undeveloped Reserves requires the judgment of the evaluator taking into account the cost environment. A significant investment would be a relatively large expenditure when compared to the cost of drilling and completing a new well. A minor cost would be a lower expenditure when compared to the cost of drilling and completing a new well.

Once a project passes the commercial assessment and achieves Reserves status, it is then included with all other Reserves projects of the same category in the same field for estimating combined future production and applying the economic limit test (see PRMS 2018 Section 3.1, Assessment of Commerciality).

Where Reserves remain Undeveloped beyond a reasonable time-frame or have remained Undeveloped owing to postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and to justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay (see Section A.2.1.2, Determination of Commerciality) is justified, a reasonable time-frame to commence the project is generally considered to be less than five years from the initial classification date.

Development and Production status are of significant importance for project portfolio management and financials. The Reserves status concept of Developed and Undeveloped status is based on the funding and operational status of wells and producing facilities within the development project. These status designations are applicable throughout the full range of Reserves uncertainty categories (1P, 2P, and 3P or Proved, Probable, and Possible). Even those projects that are Developed and On Production should have remaining uncertainty in recoverable quantities.

B.2.1.3.3 Economic Status

Projects may be further characterized by economic status. All projects classified as Reserves must be commercial under defined conditions (see PRMS 2018 Section 3.1, Assessment of Commerciality Assessment). Based on assumptions regarding future conditions and the impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- **Economically Viable Contingent Resources** are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because it does not meet the commercial criteria defined in Section A.2.1.2.
- **Economically Not Viable Contingent Resources** are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

The best estimate (or P50) production forecast is typically used for the economic evaluation for the commercial assessment of the project. The low case, when used as the primary case for a project decision, may be used to determine project economics. The economic evaluation of the project high case alone is not permitted to be used in the determination of the project's commerciality.

For Reserves, the best estimate production forecast reflects a specific development scenario recovery process, a certain number and type of wells, facilities, and infrastructure.

The project's low-case scenario is tested to ensure it is economic, which is required for Proved Reserves to exist (see Section A.2.2.2, Category Definitions and Guidelines). It is recommended to evaluate the low case and the high case (which will quantify the 3P Reserves) to convey the project downside risk and upside potential. The project development scenarios may vary in the number and type of wells, facilities, and infrastructure in Contingent Resources, but to recognize Reserves, there must exist the reasonable expectation to develop the project for the best estimate case.

The economic status may be identified independently of, or applied in combination with, project maturity sub-classification to more completely describe the project. Economic status is not the only qualifier that allows defining Contingent or Prospective Resources sub-classes. Within Contingent Resources, applying the project status to decision gates (and/or incorporating them in a plan to execute) more appropriately defines whether the project is placed into the sub-class of either Development Pending versus On Hold, Not Viable, or Unclarified.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

B.2.2 Resources Categorization

The horizontal axis in the resources classification in Figure A.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
- Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

There must be a single set of defined conditions applied for resource categorization. Use of different commercial assumptions for categorizing quantities is referred to as "split conditions" and are not allowed. Frequently, an entity will conduct project evaluation sensitivities to understand potential implications when making project selection decisions. Such sensitivities may be fully aligned to resource categories or may use single parameters, groups of parameters, or variances in the defined conditions.

Moreover, a single project is uniquely assigned to a sub-class along with its uncertainty range. For example, a project cannot have quantities classified in both Contingent Resources and Reserves, for instance as 1C, 2P, and 3P. This is referred to as "split classification."

B.2.2.1 Range of Uncertainty

Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see PRMS 2018 Section 4.2, Resources Assessment Methods).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section A.2.2.2, Category Definitions and Guidelines).

Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

While there may be significant chance that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independent of such likelihood when considering what resources class to assign the project quantities.

B.2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see PRMS 2018 Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

Use of consistent terminology (Figure A.1 and Figure A.3) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. PRMS 2018 Table 3 provides criteria for the Reserves categories determination.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see PRMS 2018 Section 4.2.1, Aggregating Resources Classes).

Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see PRMS 2018 Section 3.1, Assessment of Commerciality).

PRMS 2018 Tables 1, 2, and 3 present category definitions and provide guidelines designed to promote consistency in resources assessments. The following summarize the definitions for each Reserves category in terms of both the deterministic incremental method and the deterministic scenario method, and also provides the criteria if probabilistic methods are applied. For all methods (incremental, scenario, or probabilistic), low, best and high estimate technical forecasts are prepared at an effective date (unless justified otherwise), then tested to validate the commercial criteria, and truncated as applicable for determination of Reserves quantities.

- Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Stand- alone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

One, but not the sole, criterion for qualifying discovered resources and to categorize the project's range of its low/best/high or P90/P50/P10 estimates to either 1C/2C/3C or 1P/2P/3P is the distance away from known productive area(s) defined by the geoscience confidence in the subsurface.

A conservative (low-case) estimate may be required to support financing. However, for project justification, it is generally the best-estimate Reserves or Resources quantity that passes qualification because it is considered the most realistic assessment of a project's recoverable quantities. The best estimate is generally considered to represent the sum of Proved and Probable estimates (2P) for Reserves, or 2C when Contingent Resources are cited, when aggregating a field, multiple fields, or an entity's resources.

It should be noted that under the deterministic incremental method, discrete estimates are made for each category and should not be aggregated without due consideration of associated confidence. Results from the deterministic scenario, deterministic incremental, geostatistical and probabilistic methods applied to the same project should give comparable results (see PRMS 2018 Section 4.2, Resources Assessment Methods).

If material differences exist between the results of different methods, the evaluator should be prepared to explain these differences.

B.2.3 Incremental Projects

The initial resources assessment is based on application of a defined initial development project, even extending into Prospective Resources. Incremental projects are designed to either increase recovery efficiency, reduce costs, or accelerate production through either maintenance of or changes to wells, completions, or facilities or through infill drilling or by means of improved recovery. Such projects are classified according to the resources classification framework (Figure A.1), with preference for applying project maturity sub-classes (Figure A.3). Related incremental quantities are similarly categorized on the range of uncertainty of recovery. The projected recovery change can be included in Reserves if the degree of commitment is such that the project has achieved commercial maturity (See Section A.2.1.2, Determination of Commerciality). The quantity of such incremental recovery must be supported by technical evidence to justify the relative confidence in the resources category assigned.

An incremental project must have a defined development plan. A development plan may include projects targeting the entire field (or even multiple, linked fields), reservoirs, or single wells. Each incremental project will have its own planned timing for execution and resource quantities attributed to the project. Development plans may also include appraisal projects that will lead to subsequent project decisions based on appraisal outcomes.

Circumstances when development will be significantly delayed and where it is considered that Reserves are still justified should be clearly documented. If there is no longer the reasonable expectation of project execution (i.e., historical track record of execution, project progress), forecast project incremental recoveries are to be reclassified as Contingent Resources (see PRMS 2018 Section 2.1.2, Determination of Commerciality).

B.2.3.1 Workovers, Treatments and Changes of Equipment

Incremental recovery associated with a future workover, treatment (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures where such projects have routinely been successful in analogous reservoirs may be classified as Developed Reserves, Undeveloped Reserves, or Contingent Resources, depending on the associated costs required (see Section A.2.1.3.2, Reserves Status) and the status of the project's commercial maturity elements.

Facilities that are either beyond their operational life, placed out of service, or removed from service cannot be associated with Reserves recognition. When required facilities become unavailable or out of service for longer than a year, it may be necessary to reclassify the Developed Reserves to either Undeveloped Reserves or Contingent Resources. A project that includes facility replacement or restoration of operational usefulness must be identified, commensurate with the resources classification.

B.2.3.2 Compression

Reduction in the backpressure through compression can increase the portion of in-place gas that can be commercially produced and thus included in resources estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery is included in either Undeveloped Reserves or Developed Reserves, depending on the investment on meeting the Developed or Undeveloped classification criteria. However, if the cost to implement compression is not significant, relative to the cost of one new well in the field, or there is reasonable expectation that compression will be implemented by a third party in a common sales line beyond the reference point, the incremental quantities may be classified as Developed Reserves. If compression facilities were not part of the original approved development plan and such costs are significant, it should be treated as a separate project subject to normal project maturity criteria.

B.2.3.3 Infill Drilling

Technical and commercial analyses may support drilling additional producing wells to reduce the wells spacing of the initial development plan, subject to government regulations. Infill drilling may have the combined effect of increasing recovery and acceleration production. Only the incremental recovery (i.e. recovery from infill wells less the recovery difference in earlier wells) can be considered as additional Reserves for the project; this incremental recovery may need to be reallocated.

B.2.3.4 Improved Recovery

Improved recovery is the additional petroleum obtained, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural reservoir energy. It includes secondary recovery (e.g., waterflooding and pressure maintenance), tertiary recovery processes (thermal, miscible gas injection, chemical injection, and other types), and any other means of supplementing natural reservoir recovery processes.

Improved recovery projects must meet the same Reserves technical and commercial maturity criteria as primary recovery projects.

The judgment on commerciality is based on pilot project results within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed portion of the project, where the response provides support for the analysis on which the project is based. The improved recovery project's resources will remain classified as Contingent Resources Development Pending until the pilot has demonstrated both technical and commercial feasibility and the full project passes the Justified for Development "decision gate."

B.2.4 Unconventional Resources

The types of in-place petroleum resources defined as conventional and unconventional may require different evaluation approaches and/or extraction methods. However, the PRMS resources definitions, together with the classification system, apply to all types of petroleum accumulations regardless of the in- place characteristics, extraction method applied, or degree of processing required.

- Conventional resources exist in porous and permeable rock with pressure equilibrium. The PIIP is trapped in discrete accumulations related to a local geological structure feature and/or stratigraphic condition. Each conventional accumulation is typically bounded by a down dip contact with an aquifer, as its position is controlled by hydrodynamic interactions between buoyancy of petroleum in water versus capillary force. The petroleum is recovered through wellbores and typically requires minimal processing before sale.
- Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and are not significantly affected by hydrodynamic influences (also called "continuous-type deposit"). Usually there is not an obvious structural or stratigraphic trap. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas and shale oil are sub-types of tight gas and tight oil where the lithologies are predominantly shales or siltstones. These accumulations lack the porosity and permeability of conventional reservoirs required to flow without stimulation at economic rates. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).

For unconventional petroleum accumulations, reliance on continuous water contacts and pressure gradient analysis to interpret the extent of recoverable petroleum is not possible. Thus, there is typically a need for increased spatial sampling density to define uncertainty of in-place quantities, variations in reservoir and hydrocarbon quality, and to support design of specialized mining or in-situ extraction programs. In addition, unconventional resources typically require different evaluation techniques than conventional resources.

Extrapolation of reservoir presence or productivity beyond a control point within a resources accumulation must not be assumed unless there is technical evidence to support it. Therefore, extrapolation beyond the immediate vicinity of a control point should be limited unless there is clear engineering and/or geoscience evidence to show otherwise.

The extent of the discovery within a pervasive accumulation is based on the evaluator's reasonable confidence based on distances from existing experience, otherwise quantities remain as undiscovered. Where log and core data and nearby producing analogs provide evidence of potential economic viability, a successful well test may not be required to assign Contingent Resources. Pilot projects may be needed to define Reserves, which requires further evaluation of technical and commercial viability.

A fundamental characteristic of engagement in a repetitive task is that it may improve performance over time. Attempts to quantify this improvement gave rise to the concept of the manufacturing progress function commonly called the "learning curve." The learning curve is characterized by a decrease in time and/or costs, usually in the early stages of a project when processes are being optimized. At that time, each new improvement may be significant. As the project matures, further improvements in time or cost savings are typically less substantial. In oil and gas developments with high well counts and a continuous program of activity (multi-year), the use of a learning curve within a resources evaluation may be justified to predict improvements in either the time taken to carry out the activity, the cost to do so, or both. While each development project is unique, review of analogs can provide guidance on such predictions and the range of associated uncertainty in the resulting recoverable resources estimates (see also PRMS 2018 Section 3.1.2 Economic Criteria).

Source: Petroleum Resources Management System (revised June 2018), Version 1.01, Society of Petroleum Engineers

Appendix C
Site Visit Report

No site visit has been conducted as part of our evaluation as it is usually conducted when a SPA is signed or during the transition period in which personnel specialises in Health Safety Environment would be allowed to conduct limited site visit.

Appendix D
Historical Production Plots by Field

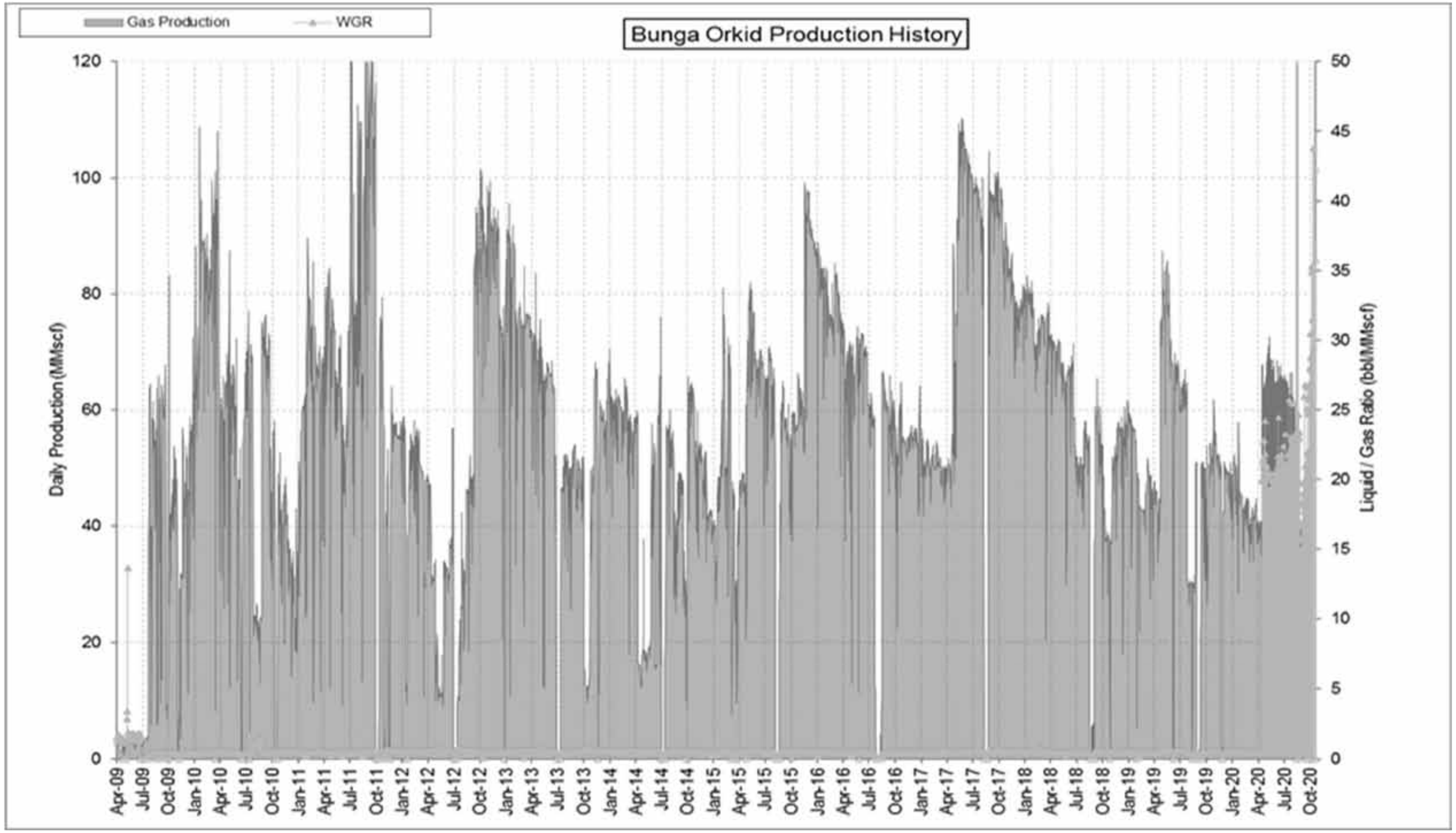


Figure D.1: Bunga Orkid Historical Gas Production

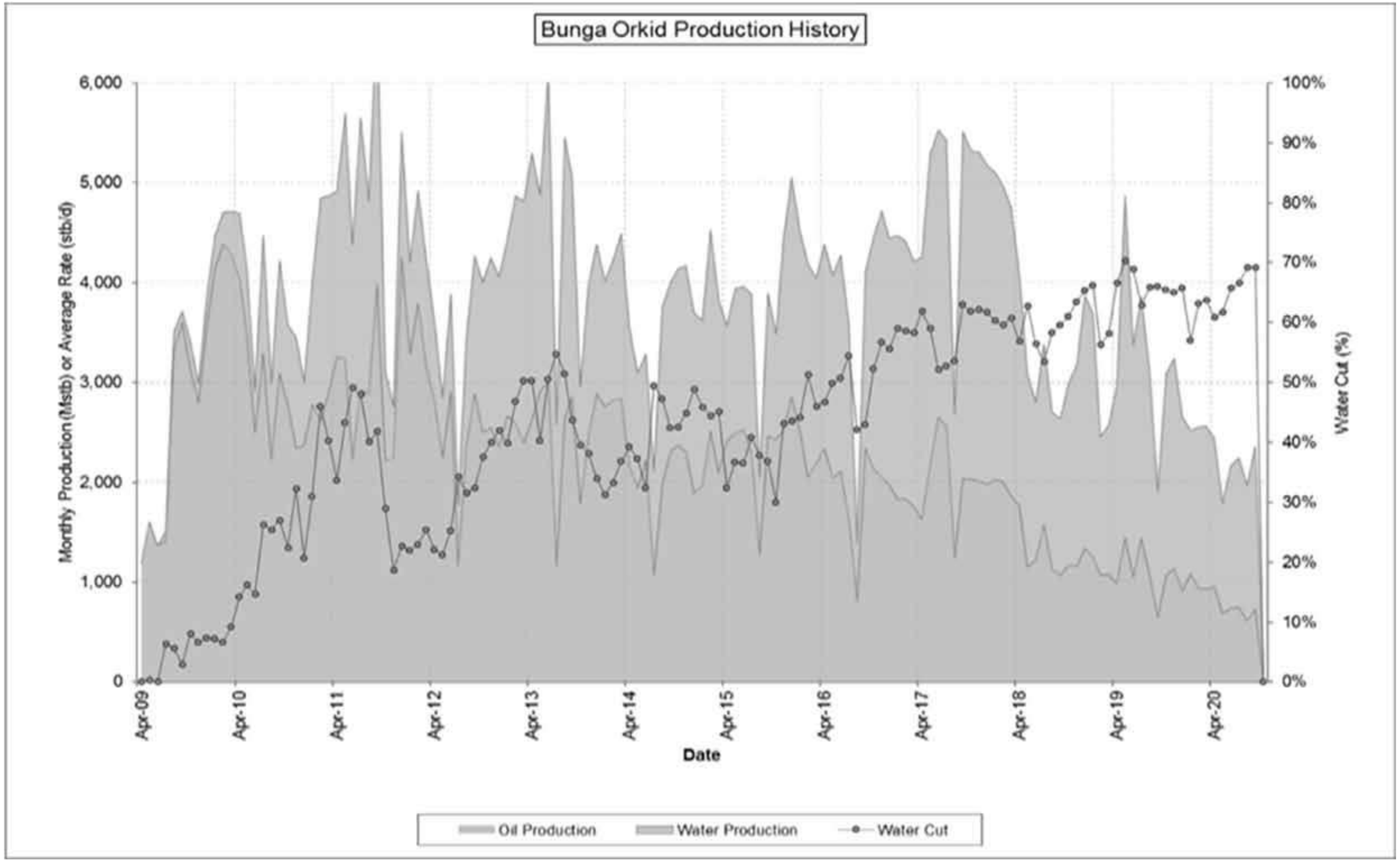


Figure D.2: Bunga Orkid Historical Oil & Condensate Production

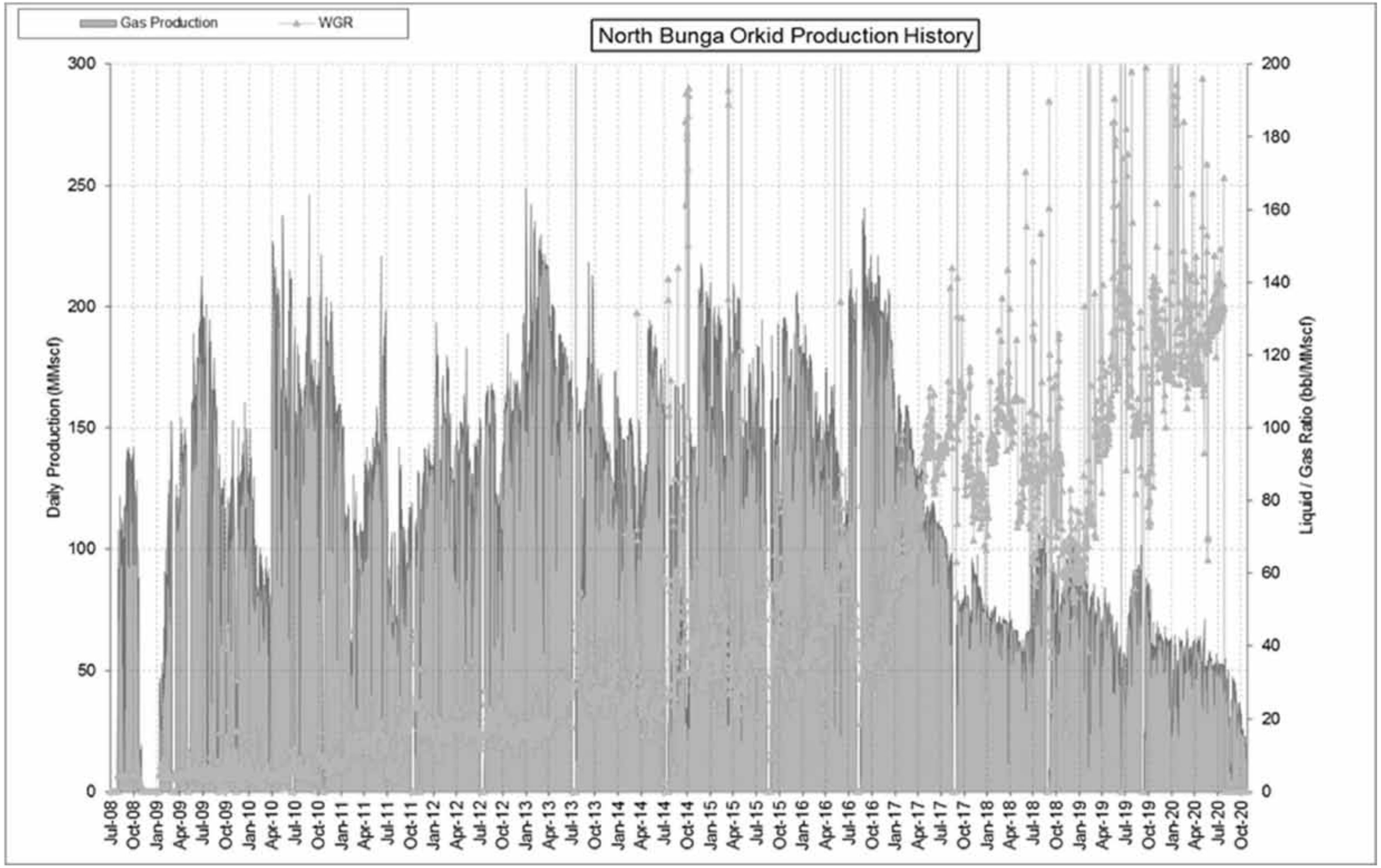


Figure D.3: North Bunga Orkid Historical Gas Production

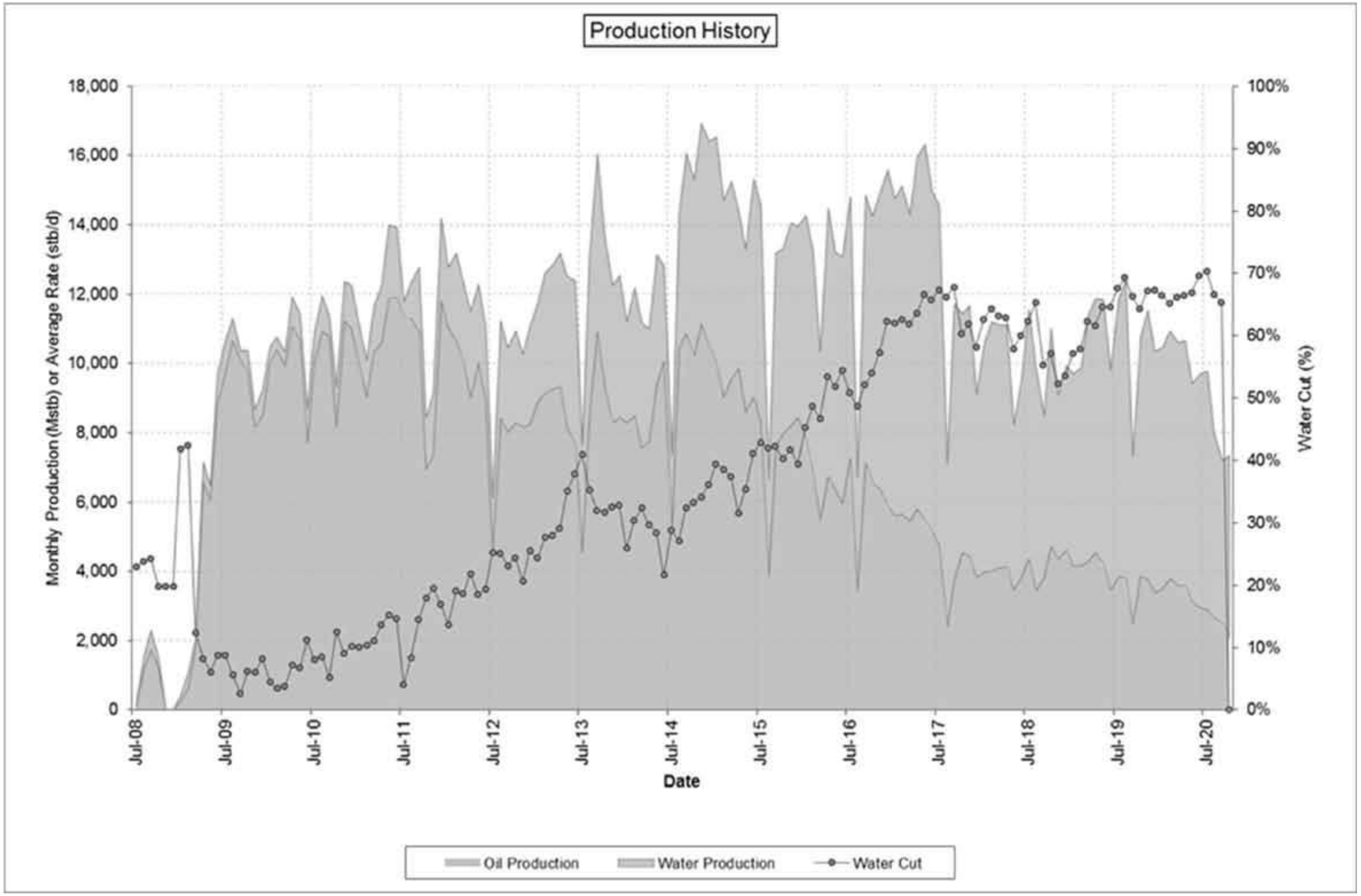


Figure D4: North Bunga Orkid Historical Oil & Condensate Production

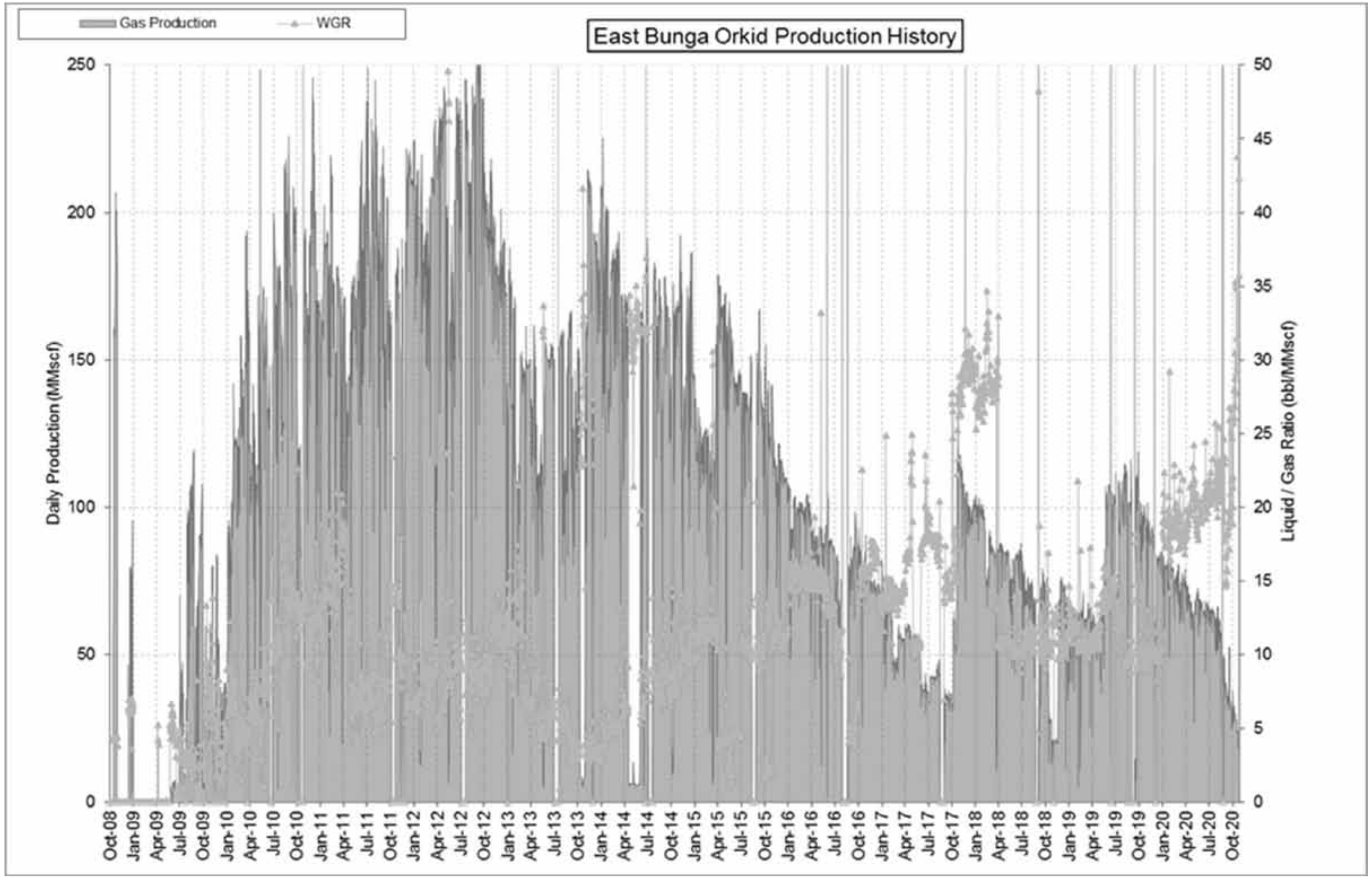


Figure D.5: East Bunga Orkid Historical Gas Production

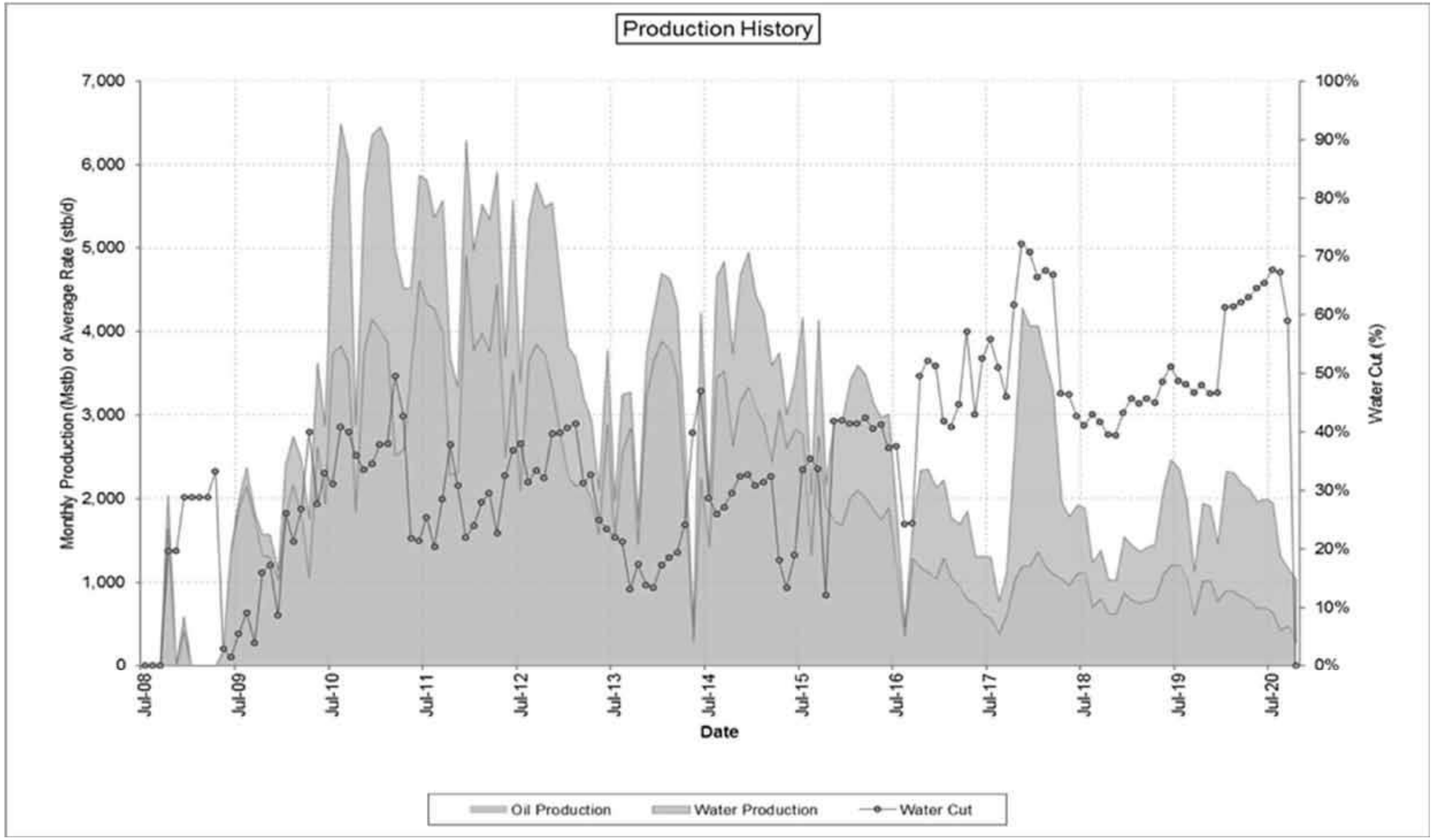


Figure D.6: **East Bunga Orkid Historical Oil & Condensate Production**

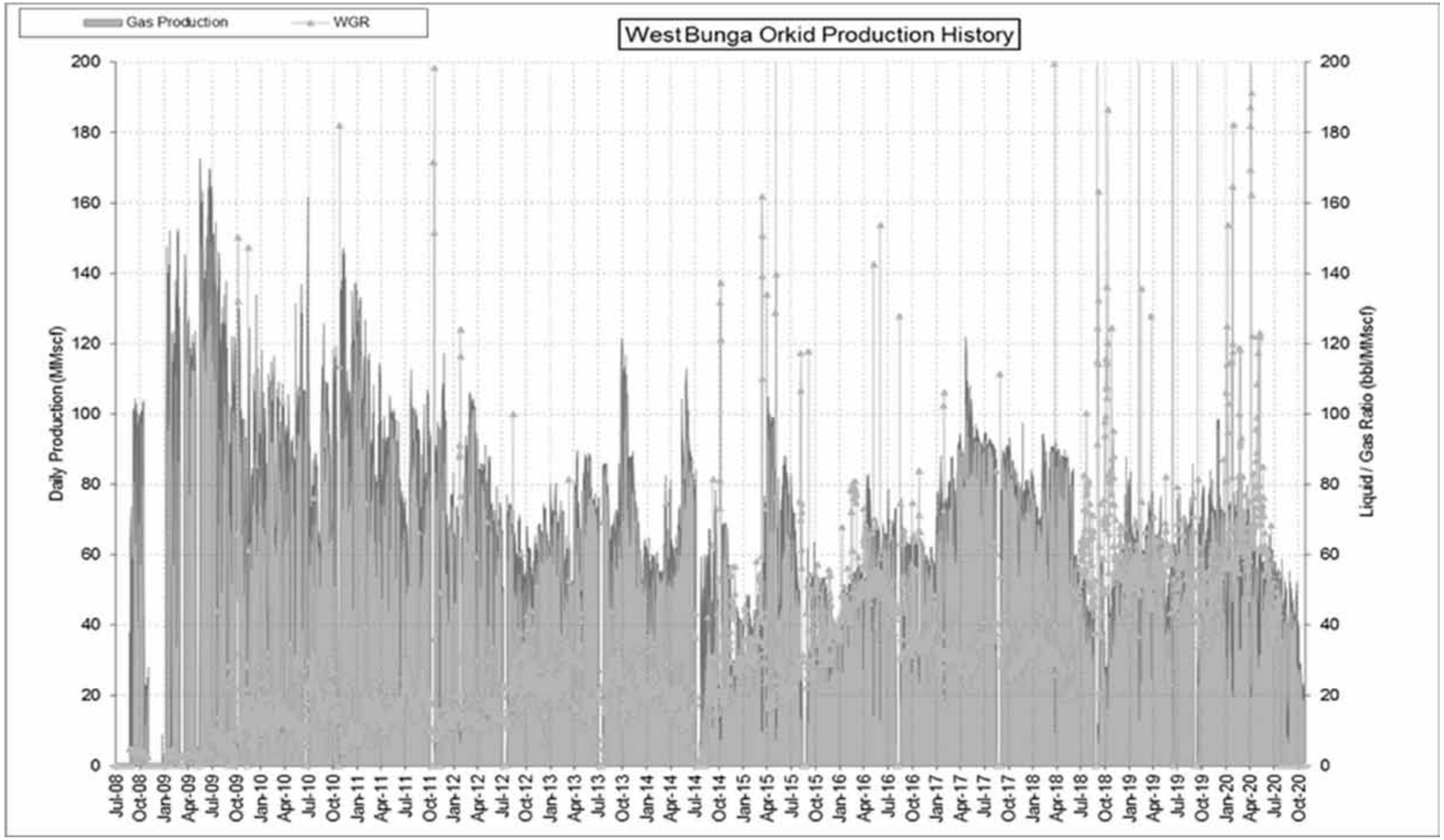


Figure D.7: West Bunga Orkid Historical Gas Production

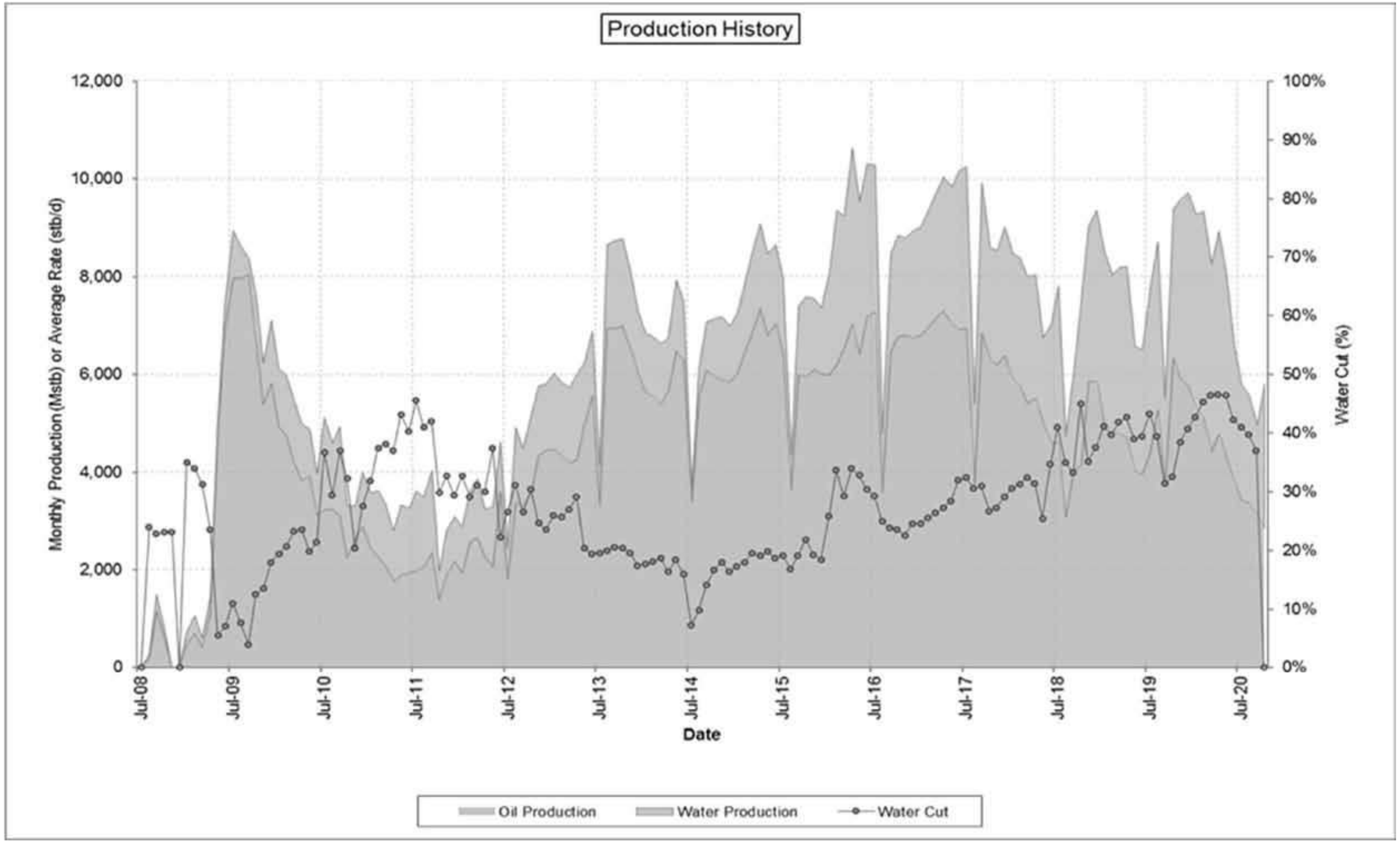


Figure D.8: **West Bunga Orkid Historical Oil & Condensate Production**

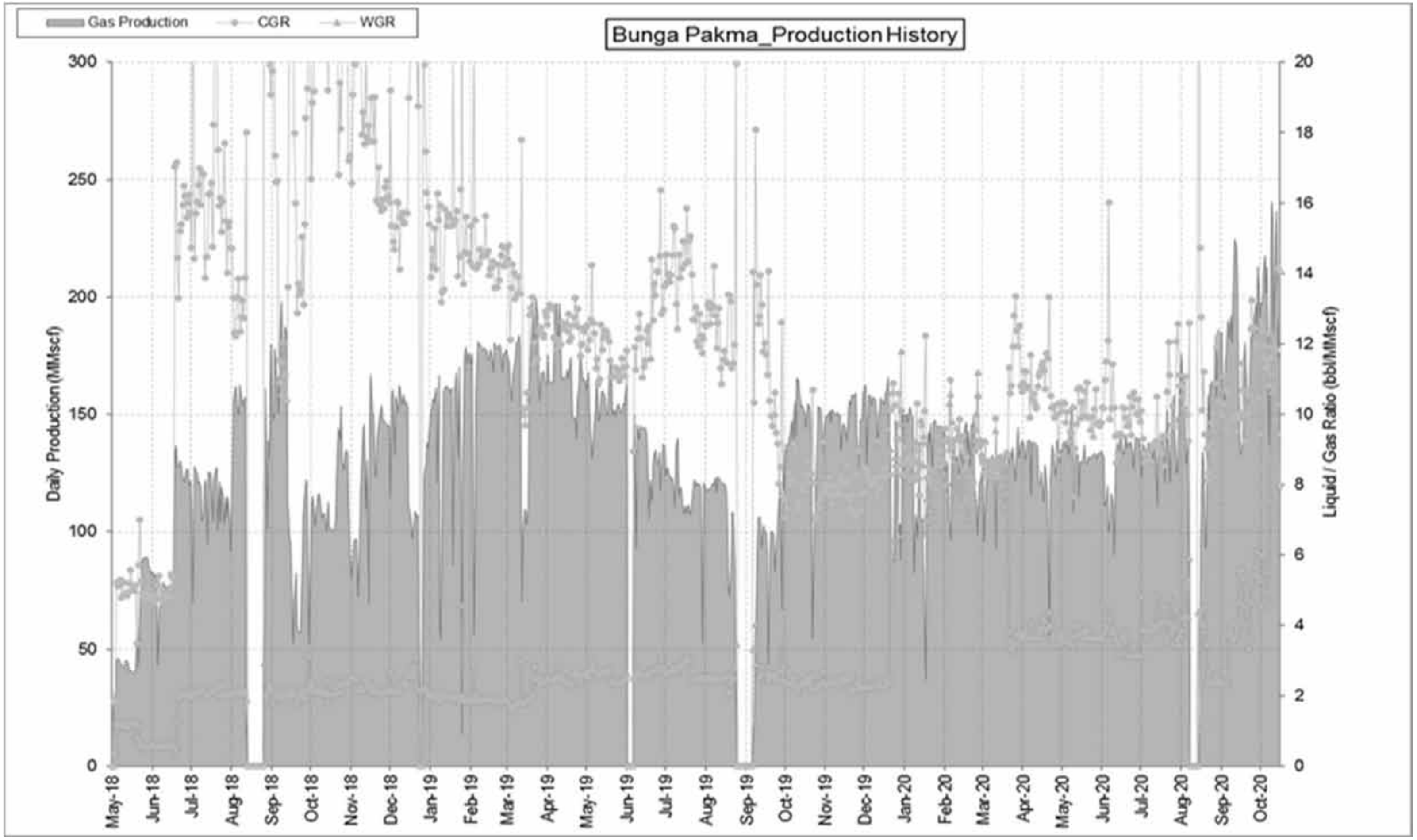


Figure D.9: Bunga Pakma (including North Bunga Pakma) Historical Gas Production

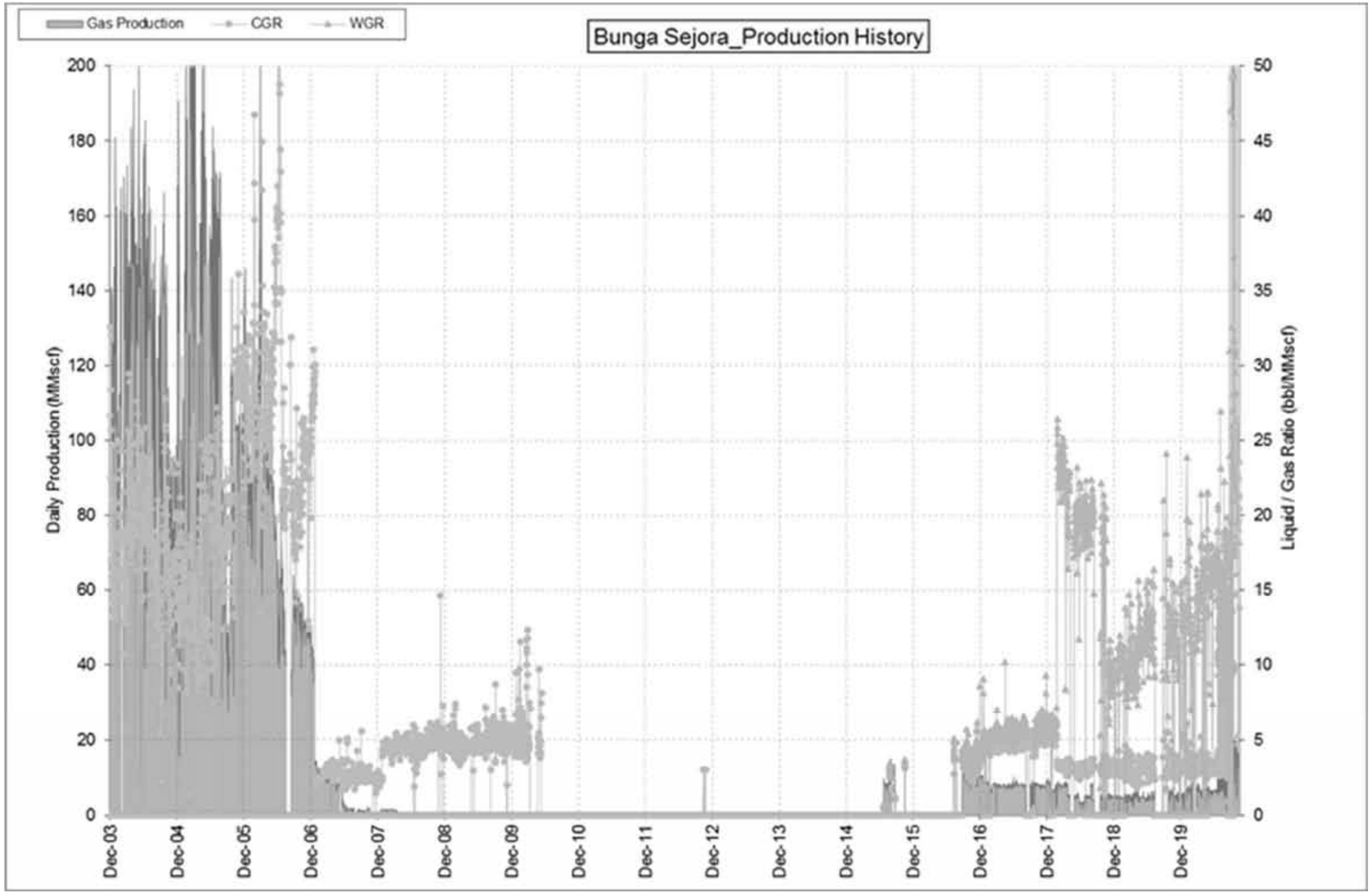


Figure D.10: Bunga Seroja Historical Gas Production

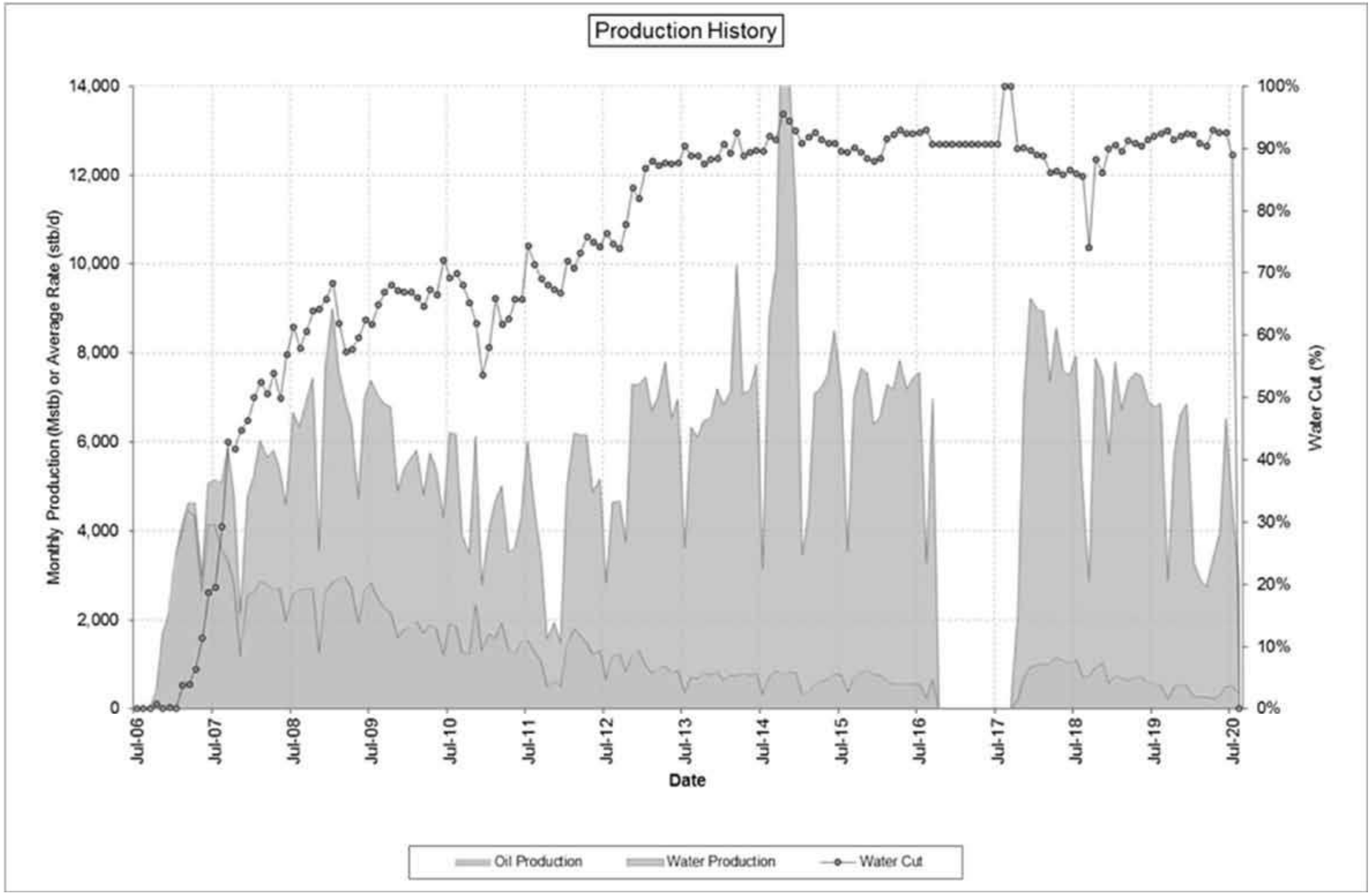


Figure D.11: Bunga Tulip Historical Oil Production

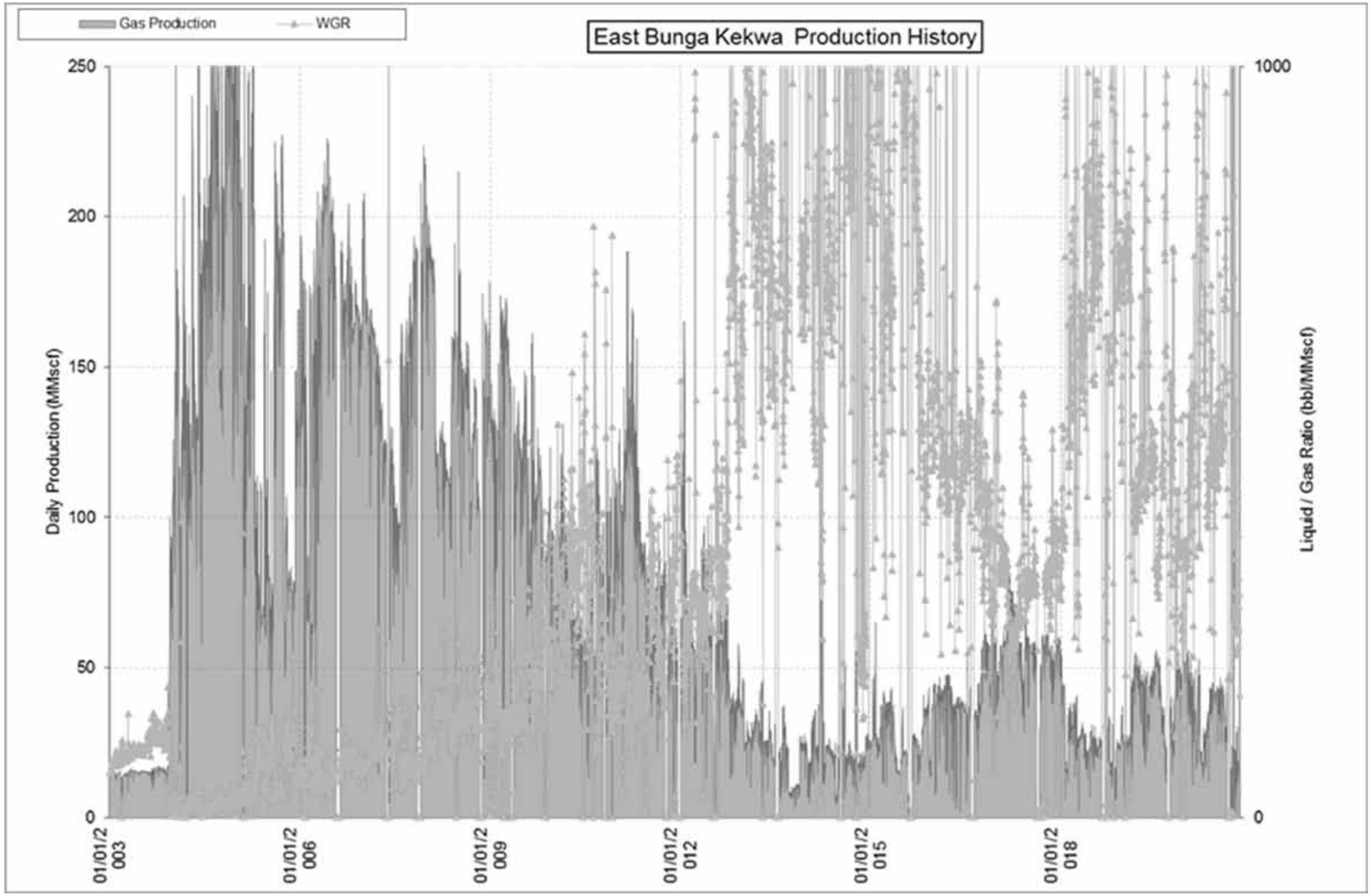


Figure D.12: East Bunga Kekwa Historical Gas Production

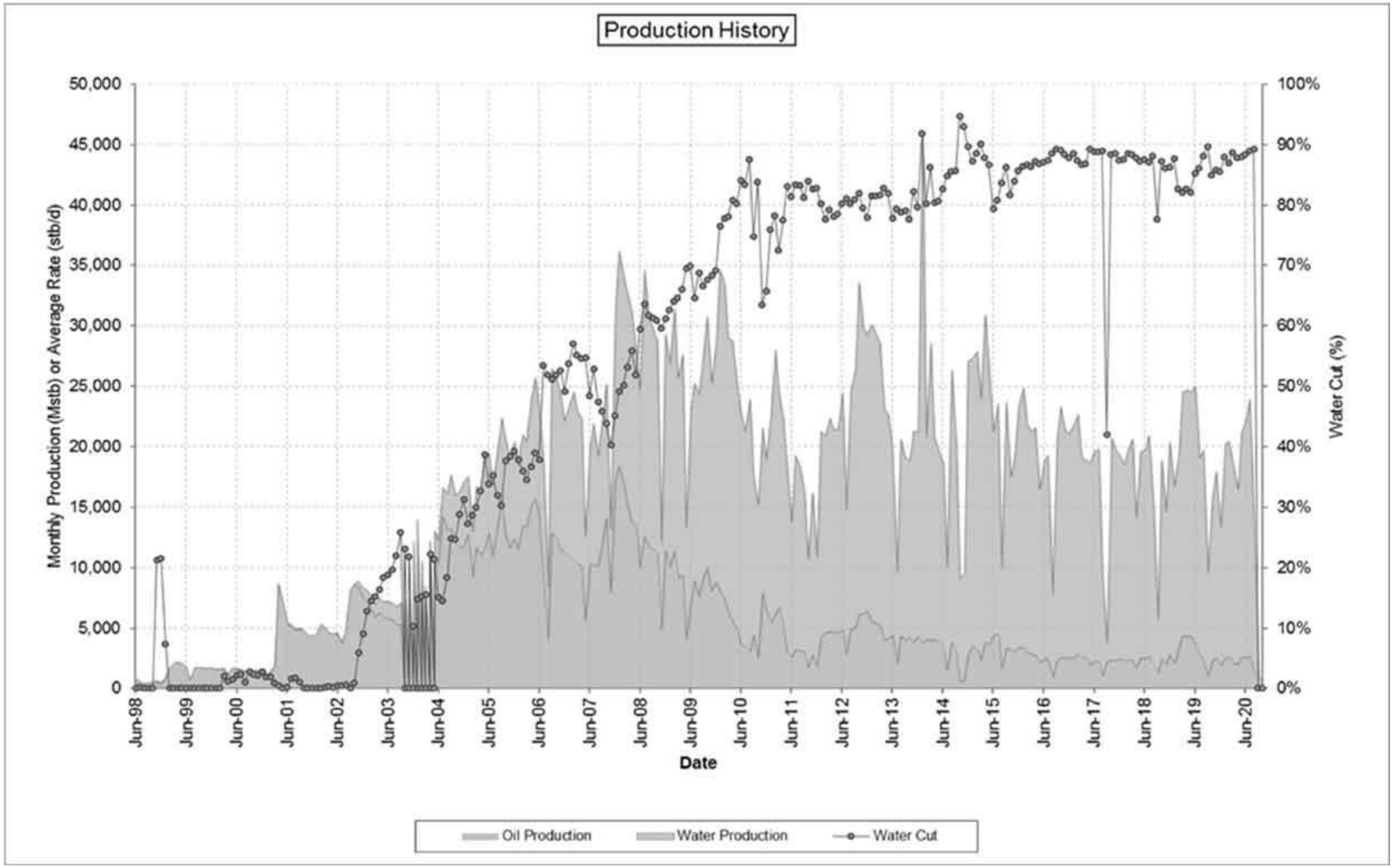


Figure D.13: East Bunga Kekwa Historical Oil & Condensate Production

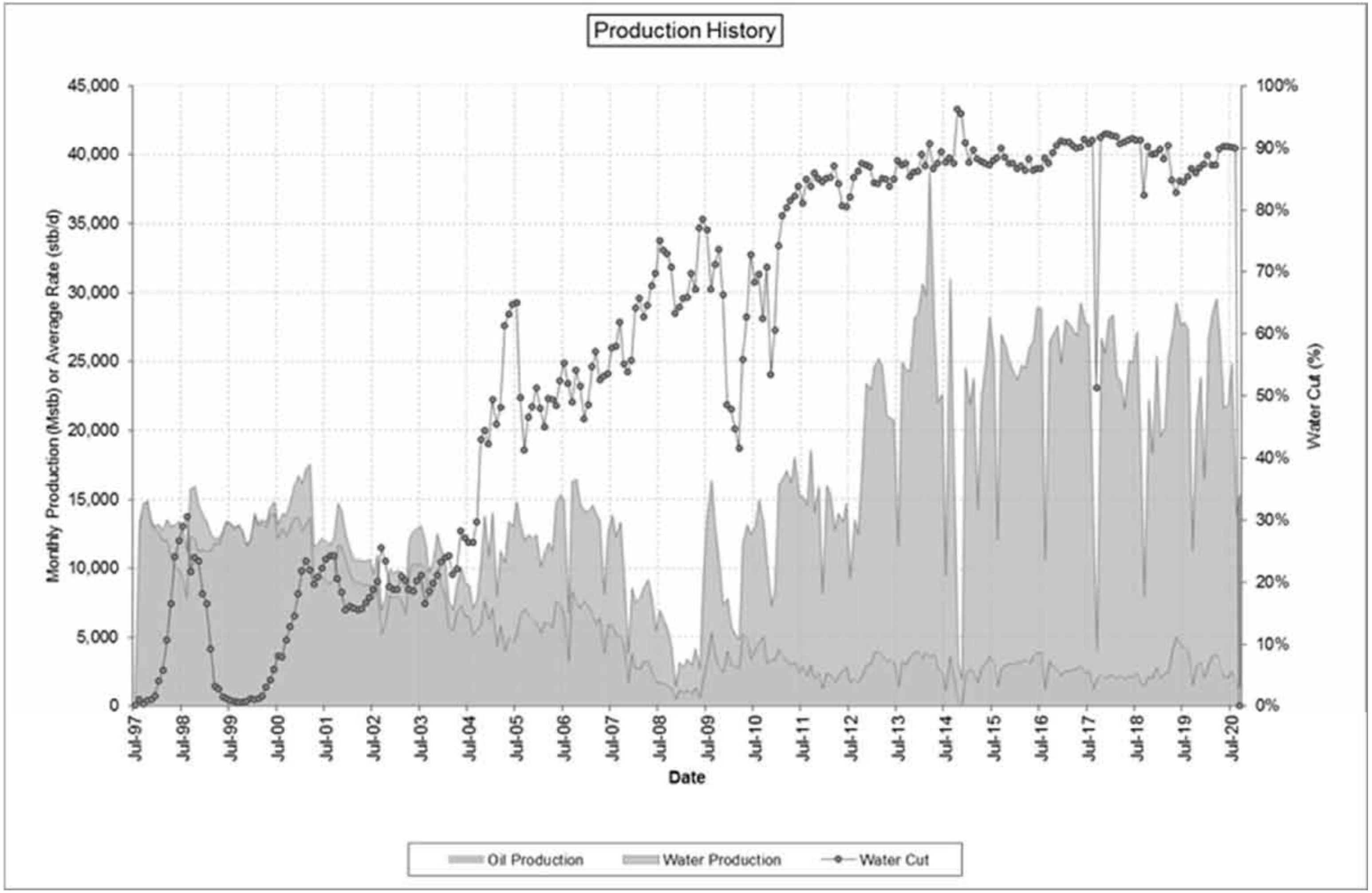


Figure D.14: West Bunga Kekwa Historical Oil & Condensate Production

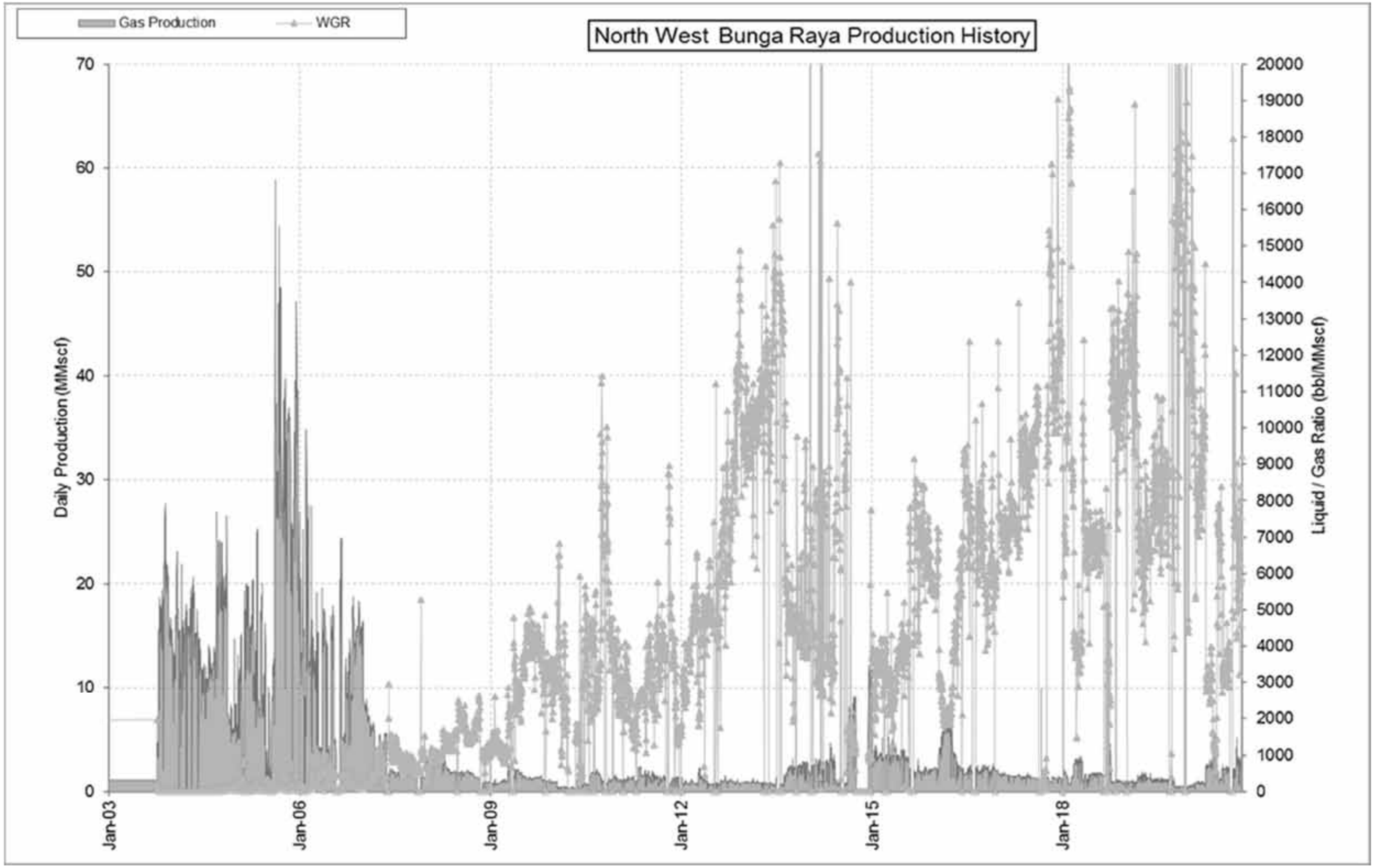


Figure D.15: Northwest Bunga Raya Historical Gas Production

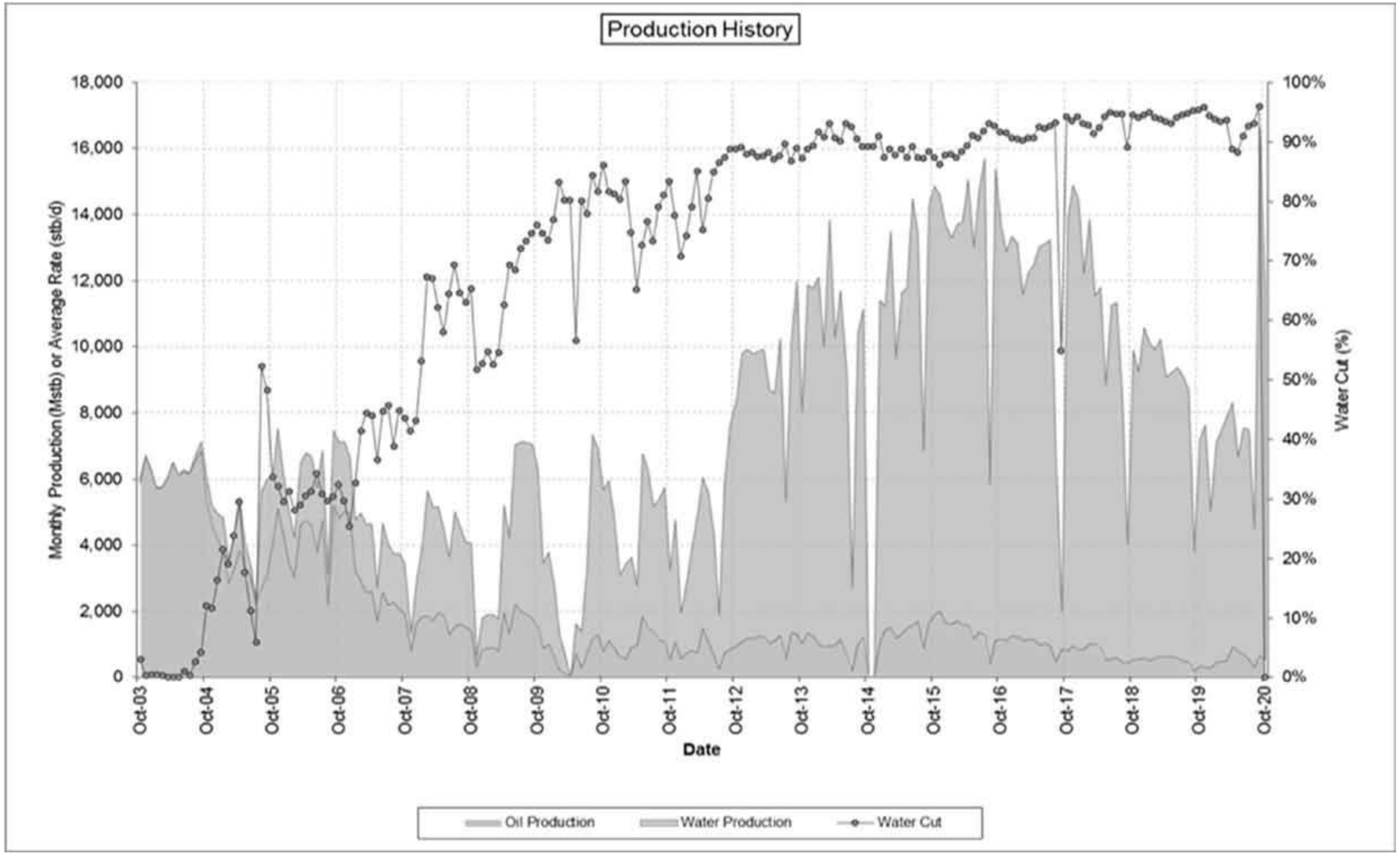


Figure D.16: Northwest Bunga Raya Historical Oil & Condensate Production

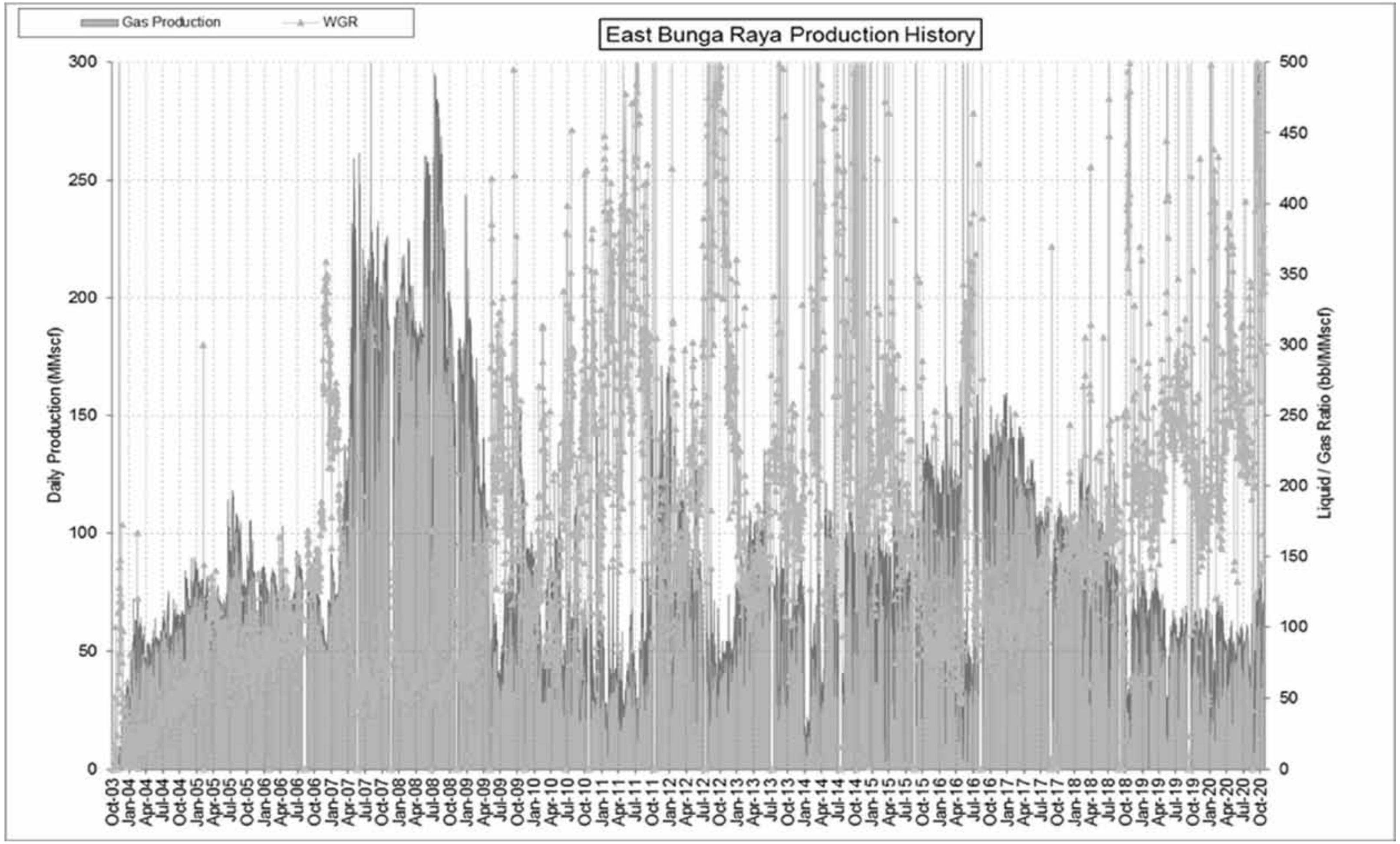


Figure D.17: East Bunga Raya Historical Gas Production

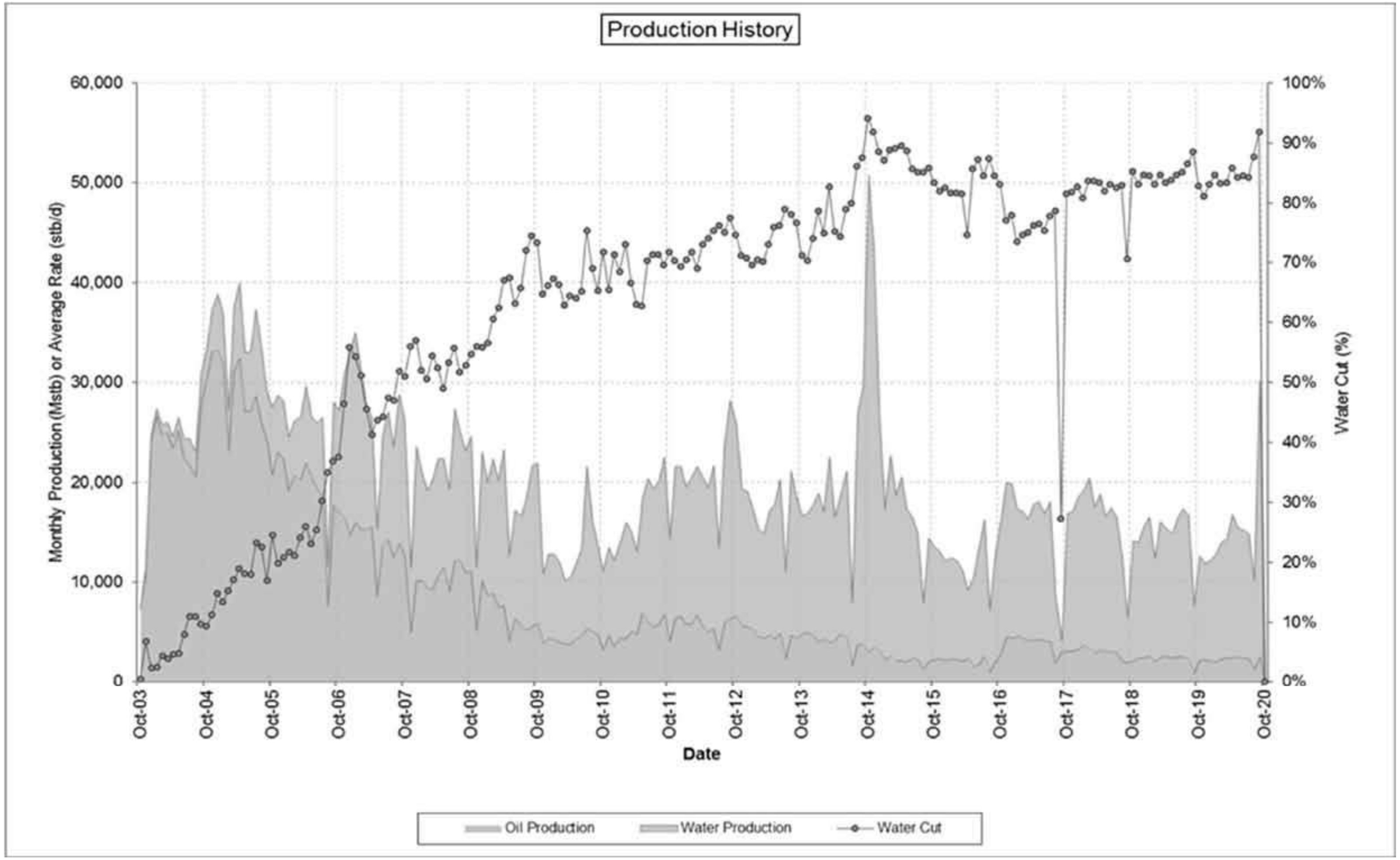


Figure D.18: East Bunga Raya Historical Oil & Condensate Production

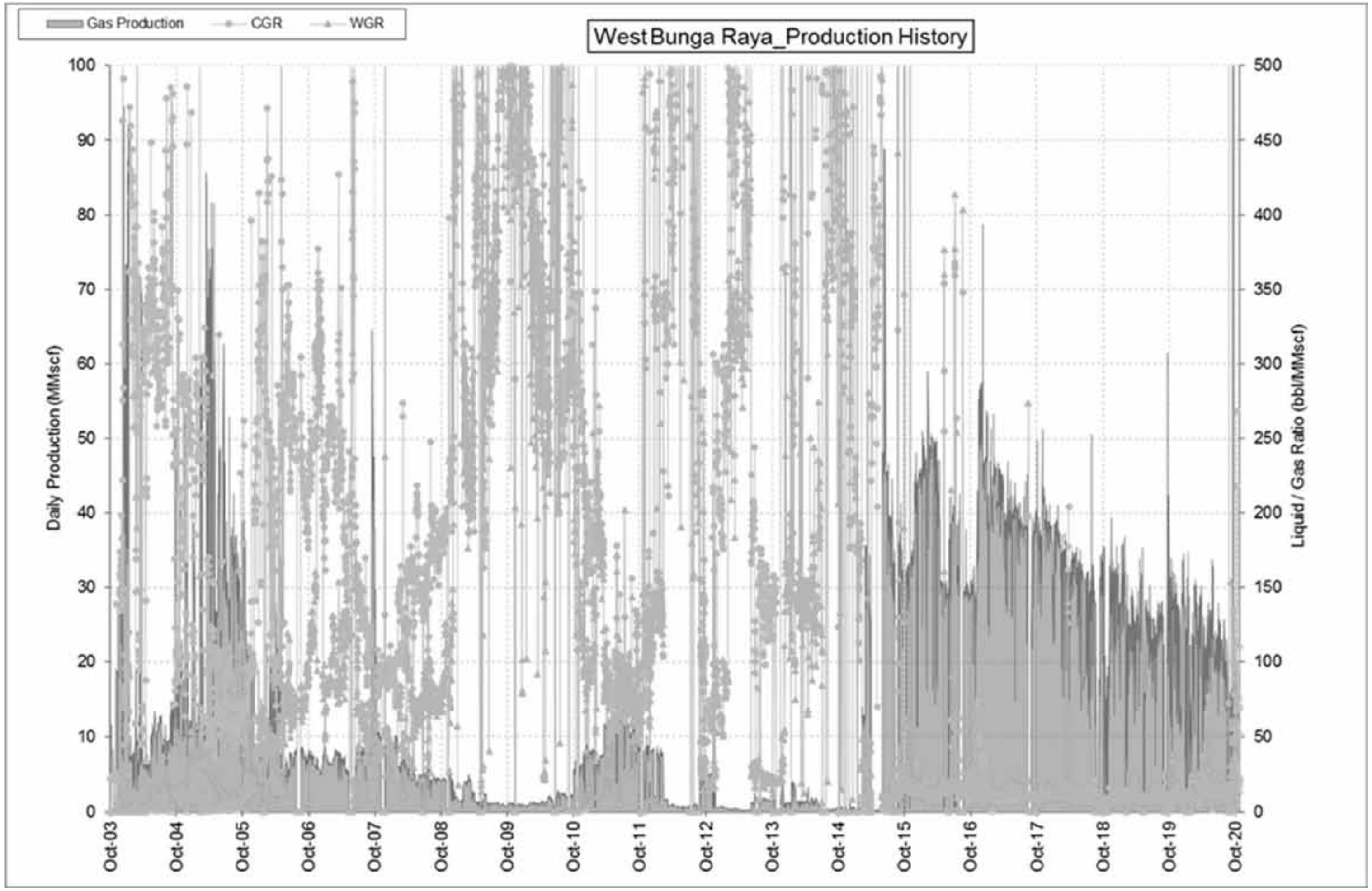


Figure D.19: West Bunga Raya Historical Gas Production

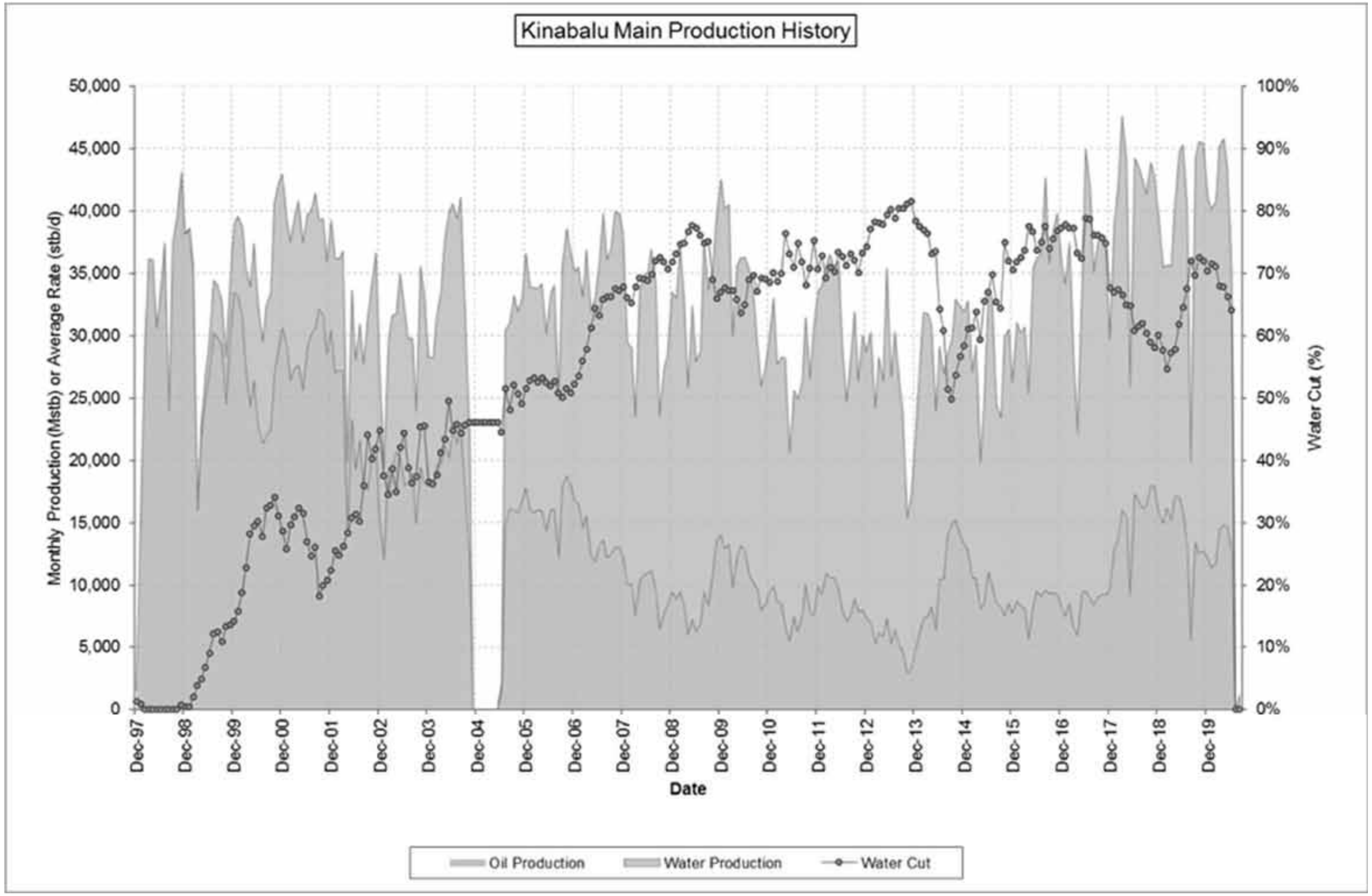


Figure D.20: Kinabalu Main Historical Oil Production

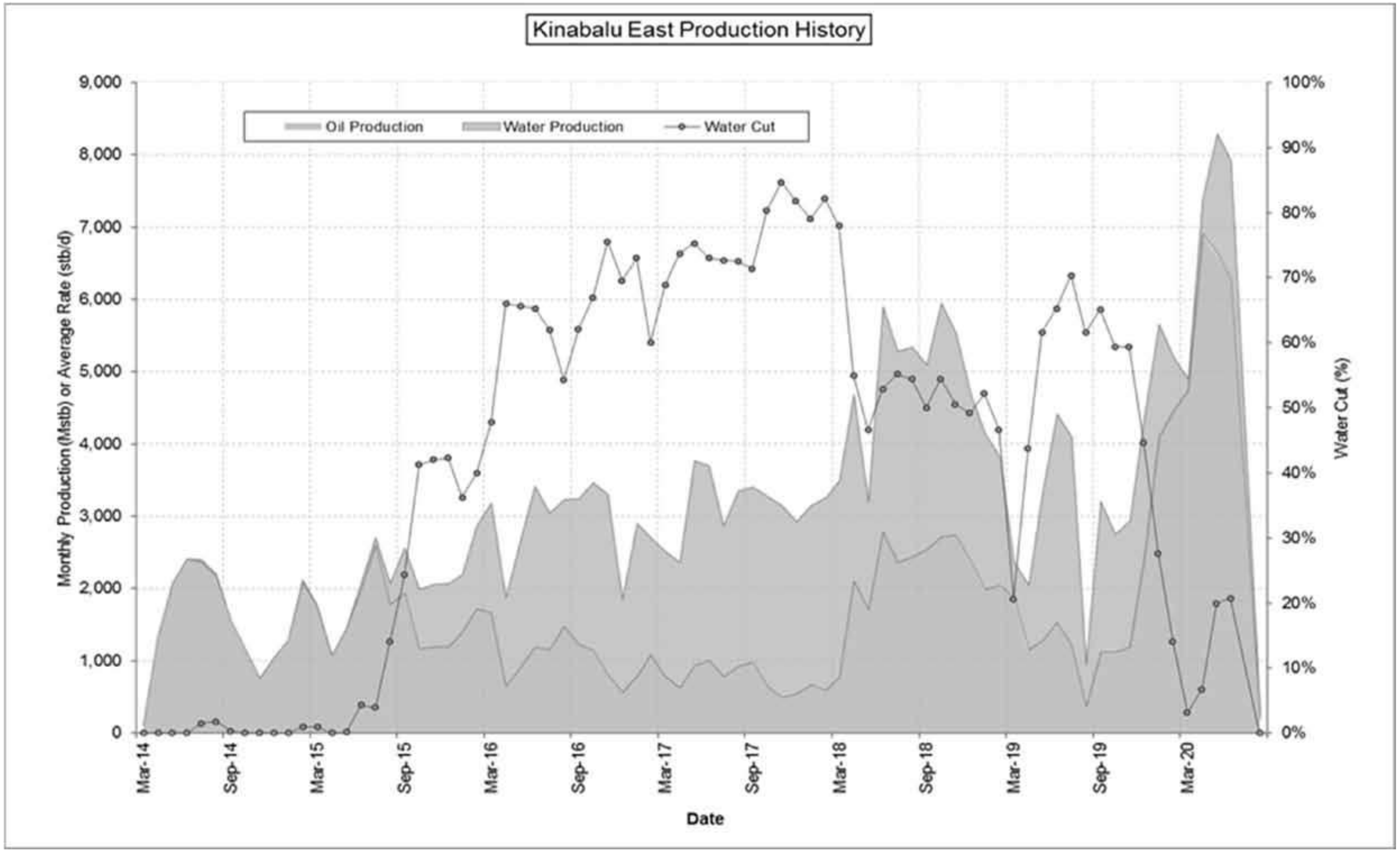


Figure D.21: Kinabalu East Historical Oil Production

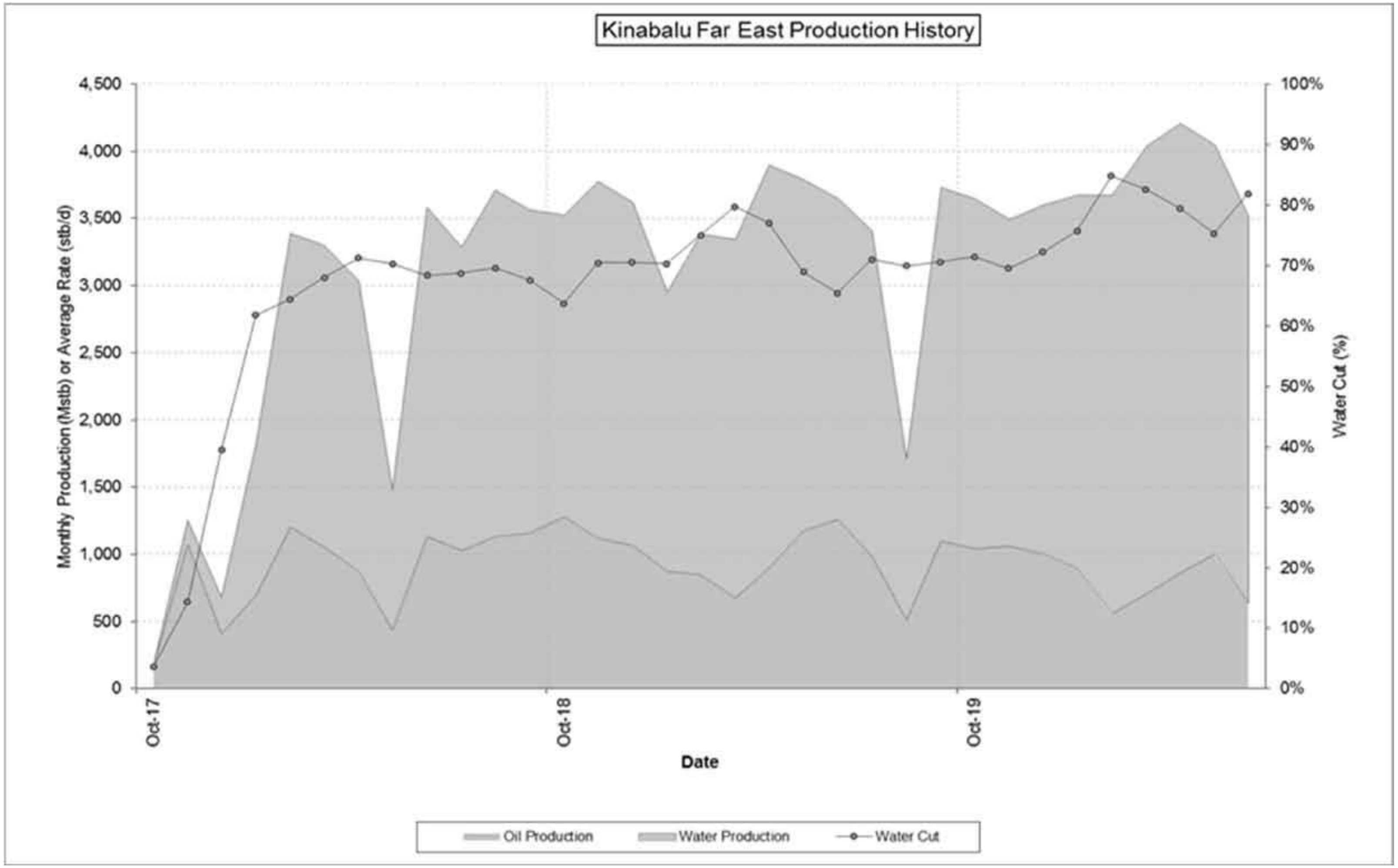


Figure D.22: Kinabalu Far East Historical Oil Production

Appendix E

Decline Curve Analysis Plots

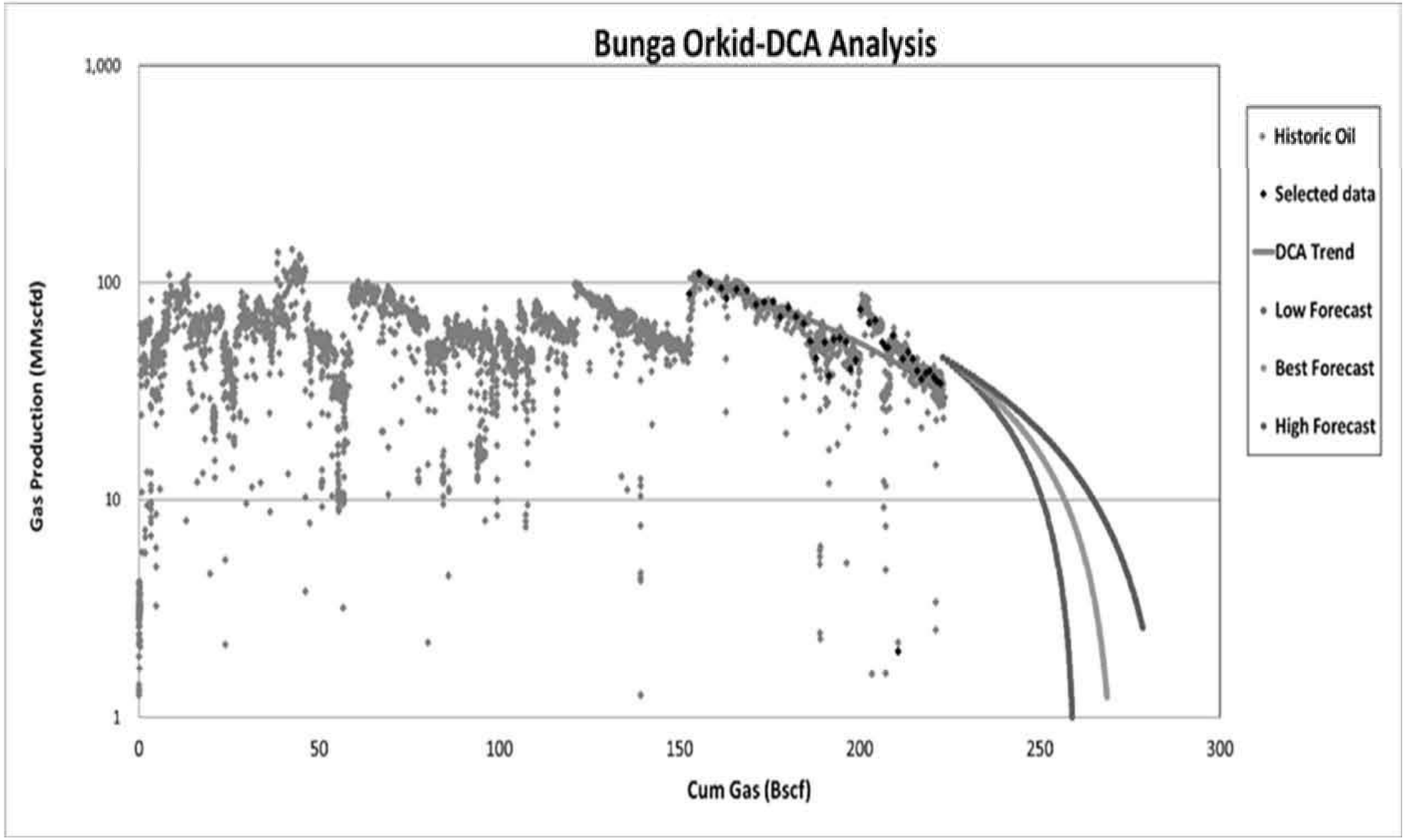


Figure E.1: Bunga Orkid Gas DCA Plot

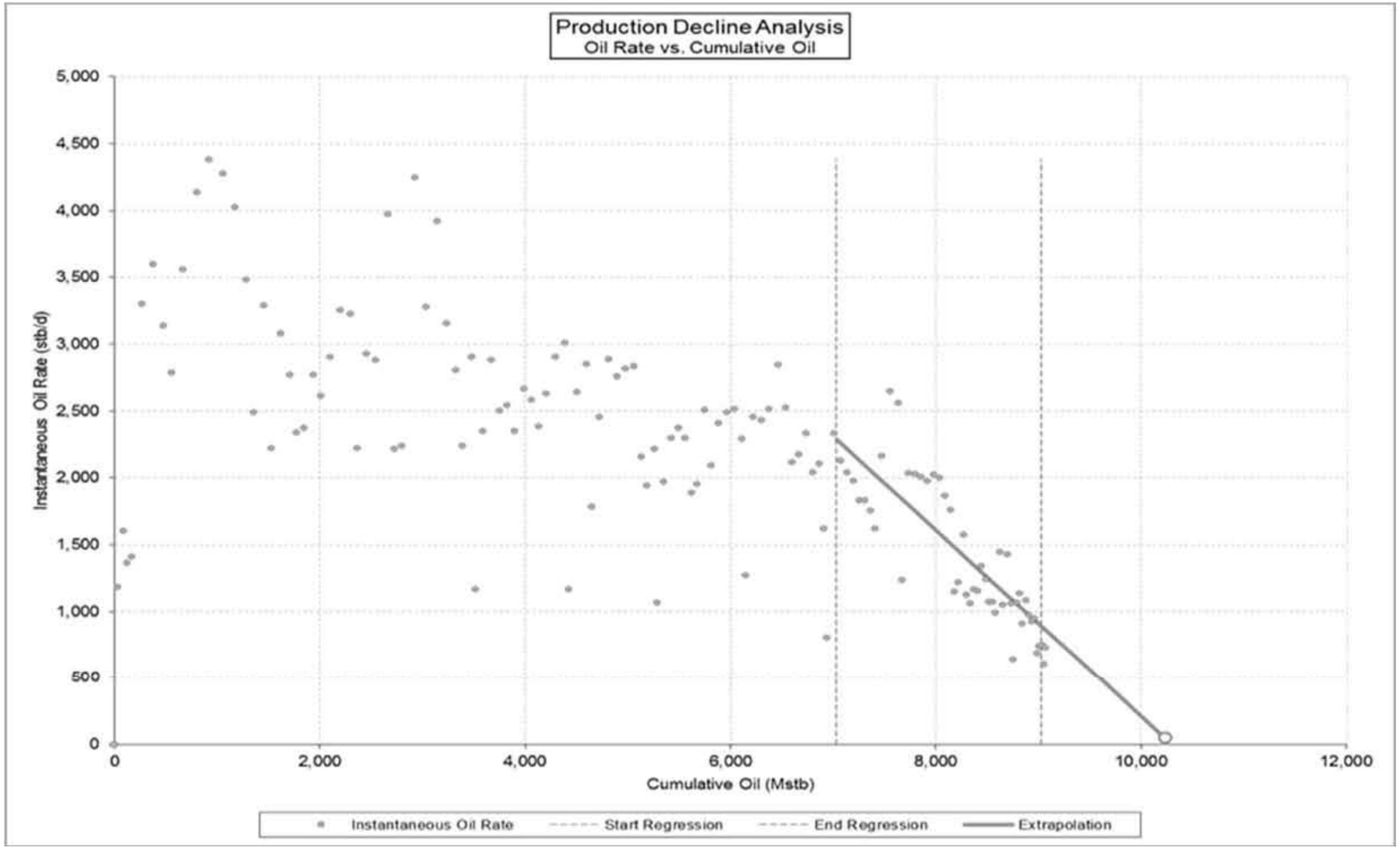


Figure E.2: Bunga Orkid Oil Rate DCA Plot

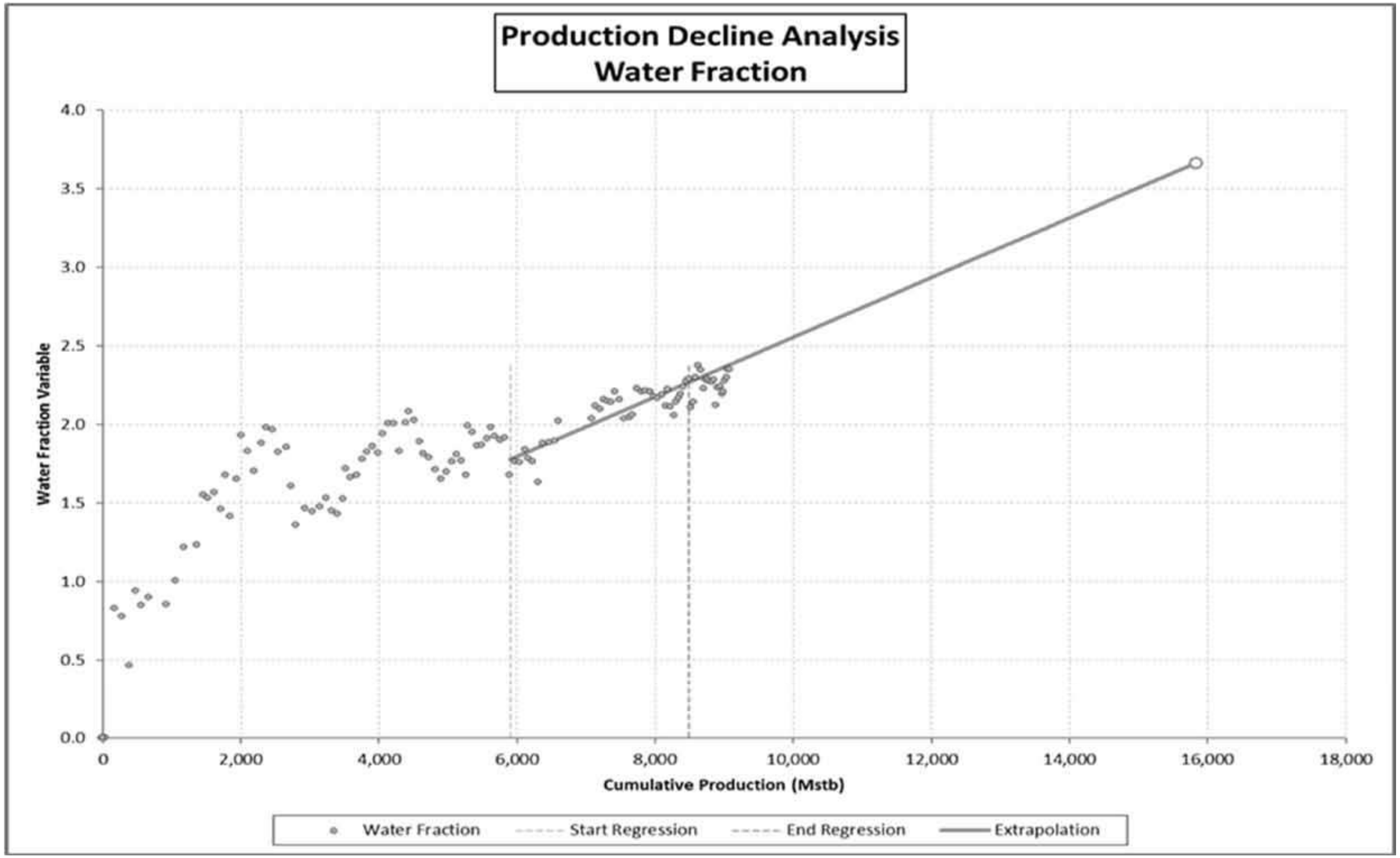


Figure E.3: Bunga Orkid WOR Analysis Plot

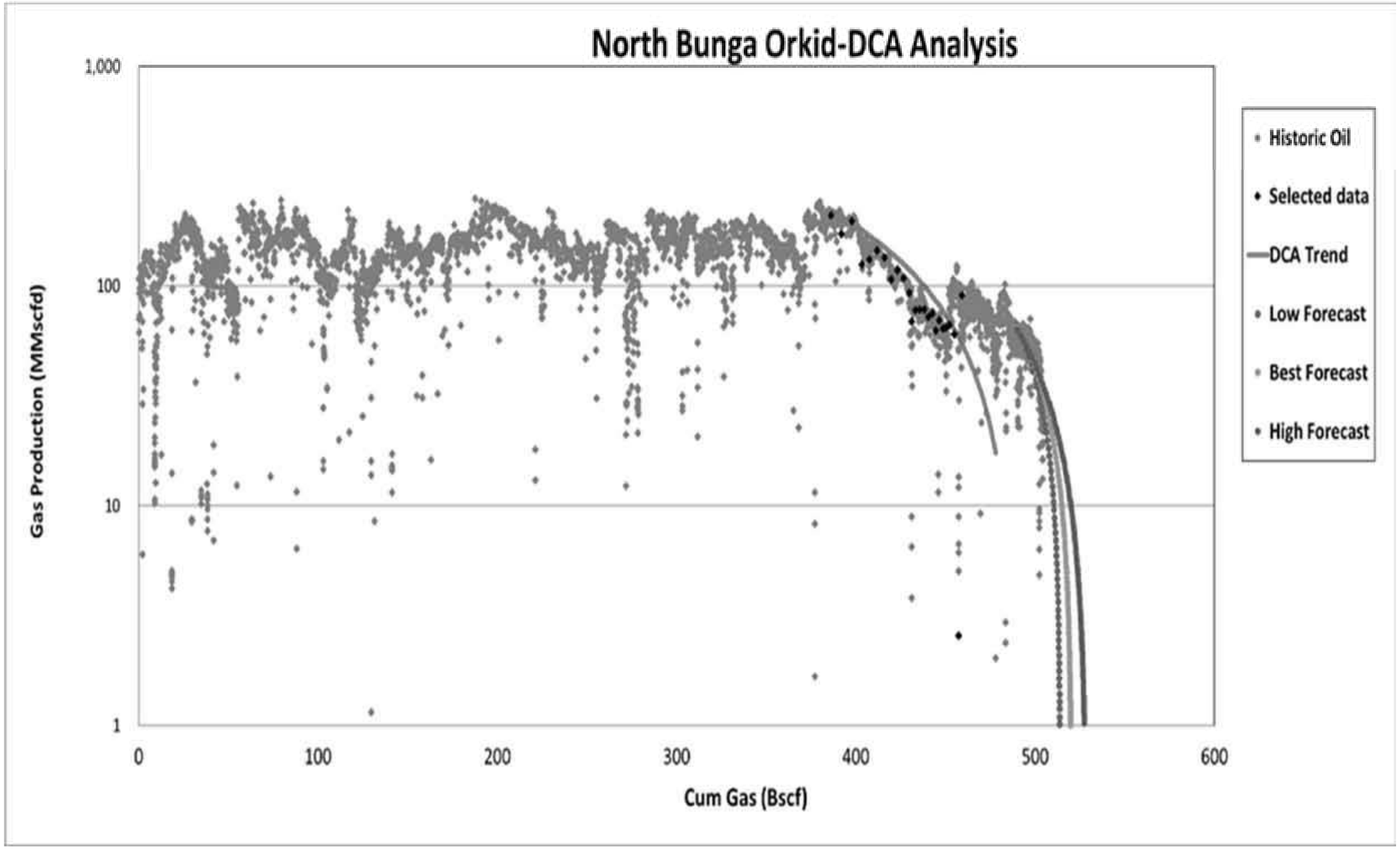


Figure E.4: North Bunga Orkid Gas DCA Plot

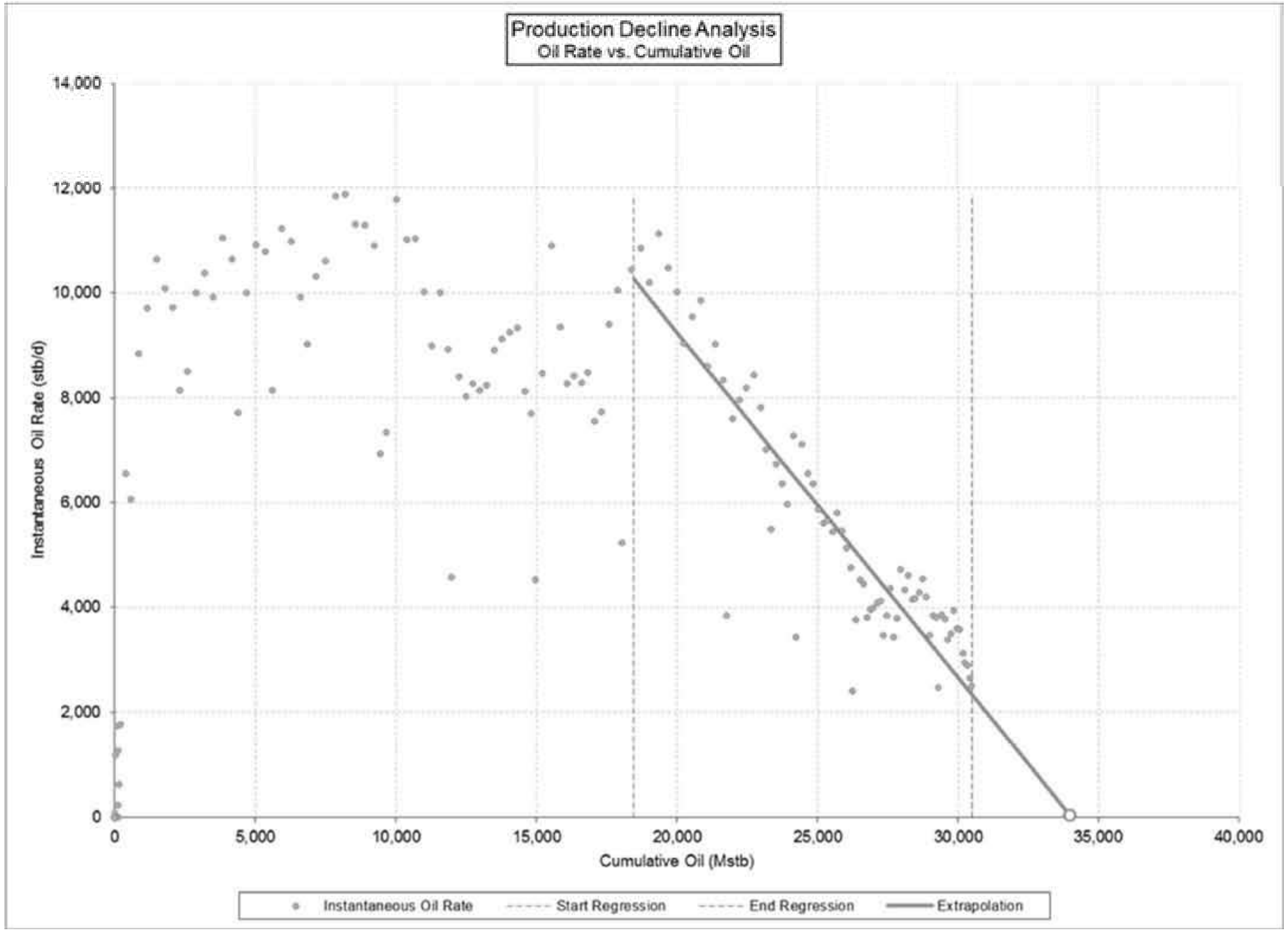


Figure E.5: North Bunga Orkid Oil Rate DCA Plot

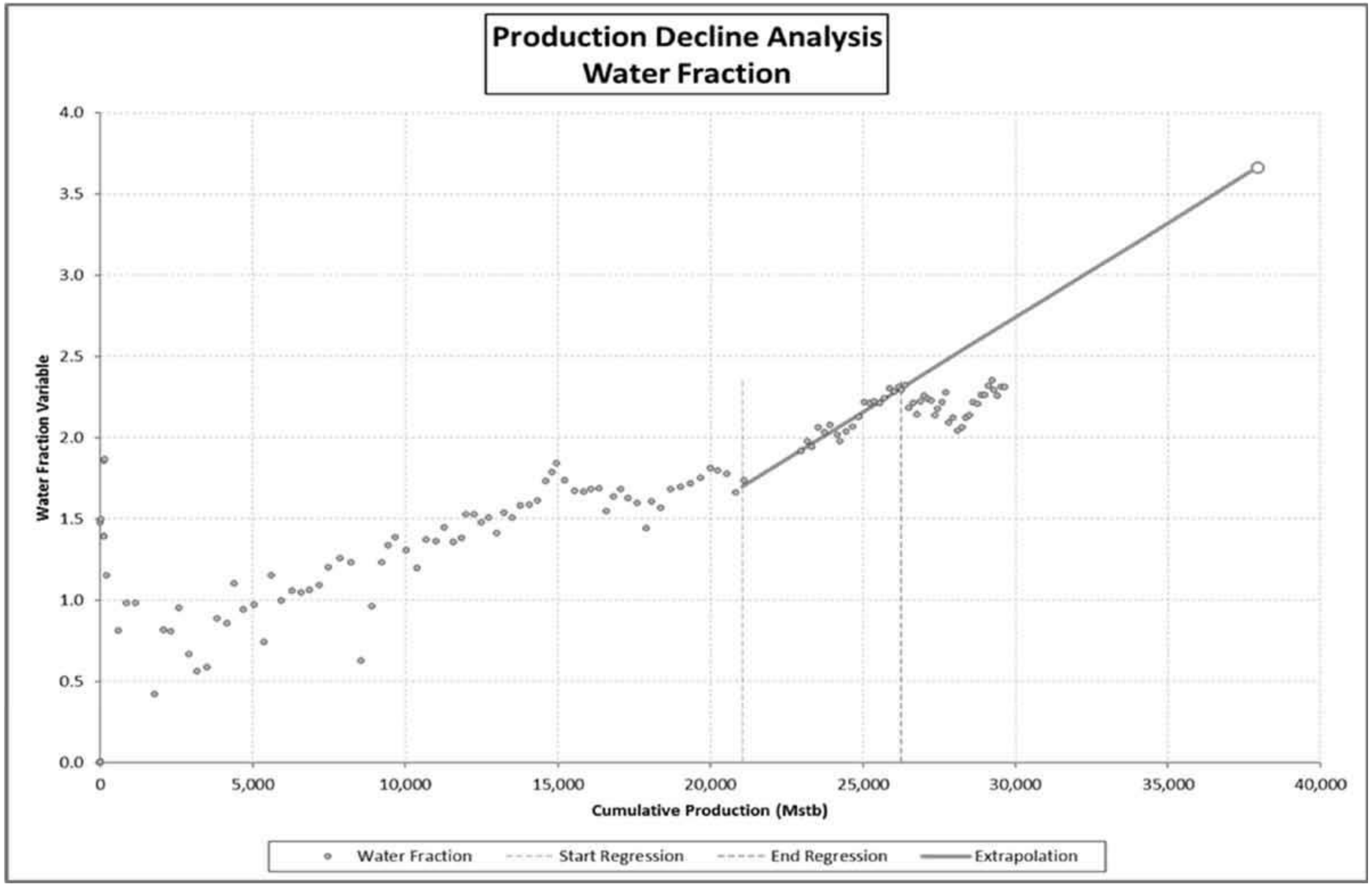


Figure E.6: North Bunga Orkid WOR Analysis Plot

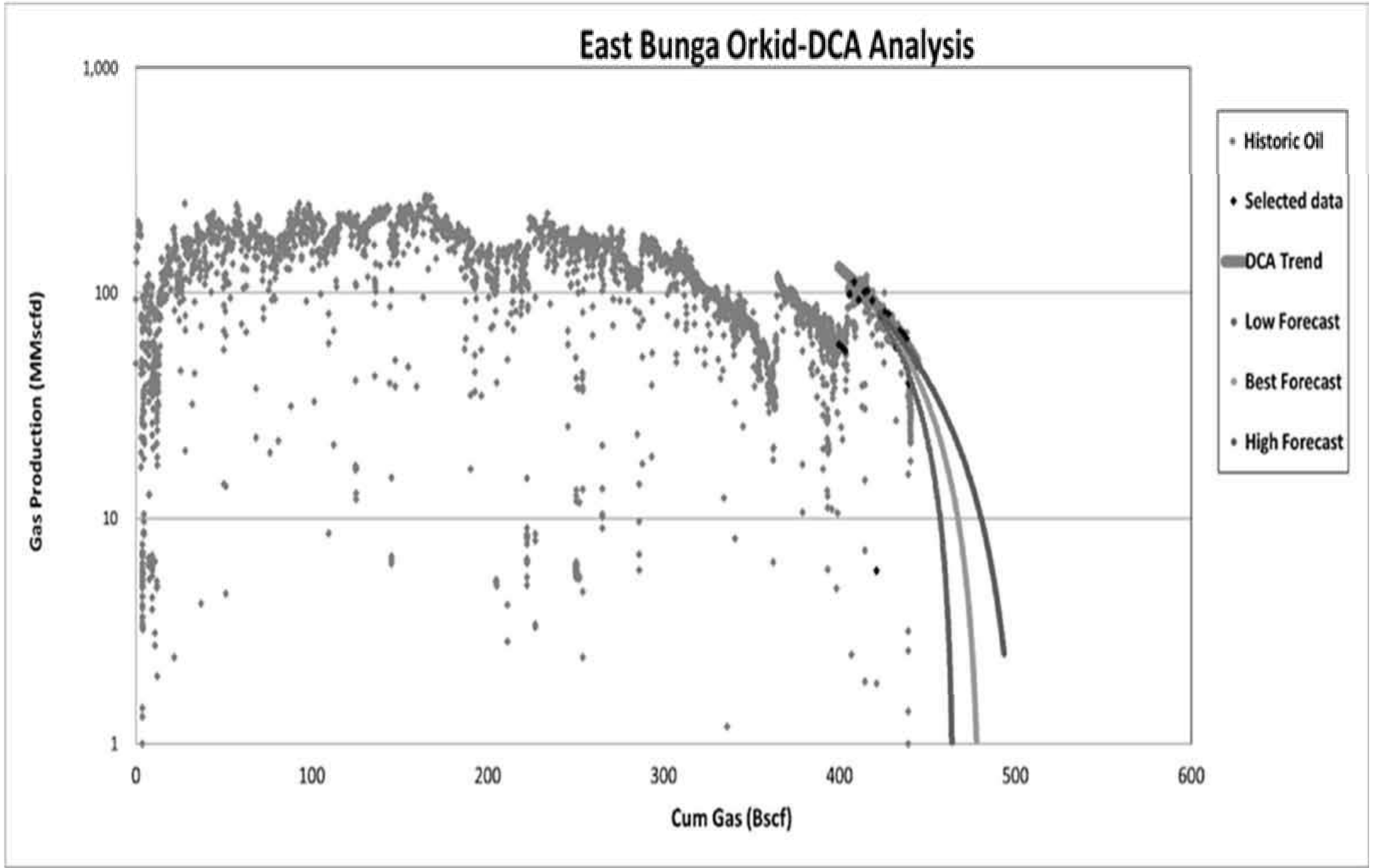


Figure E.7: **East Bunga Orkid Gas DCA Plot**

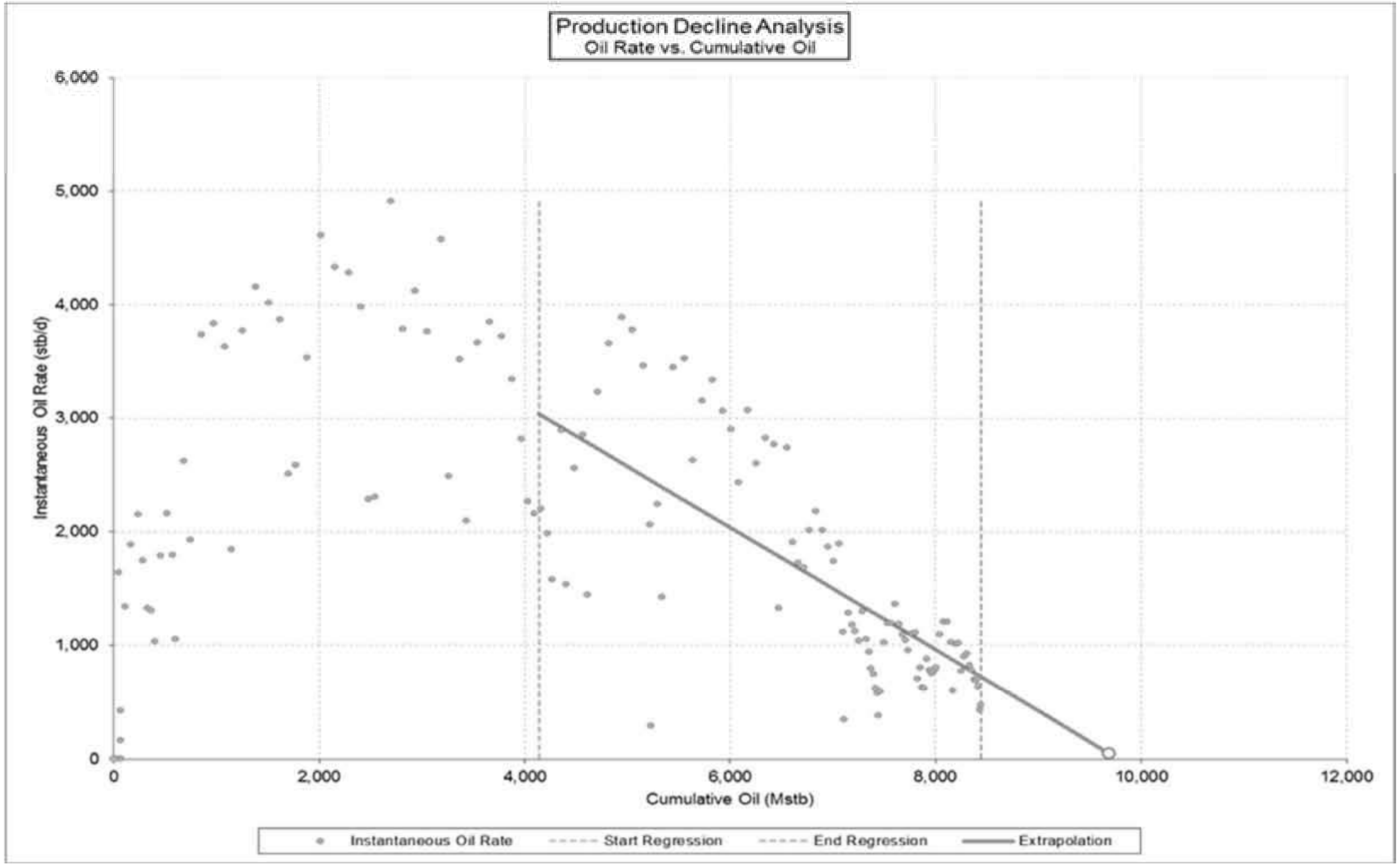


Figure E.8: East Bunga Orkid Oil DCA Plot

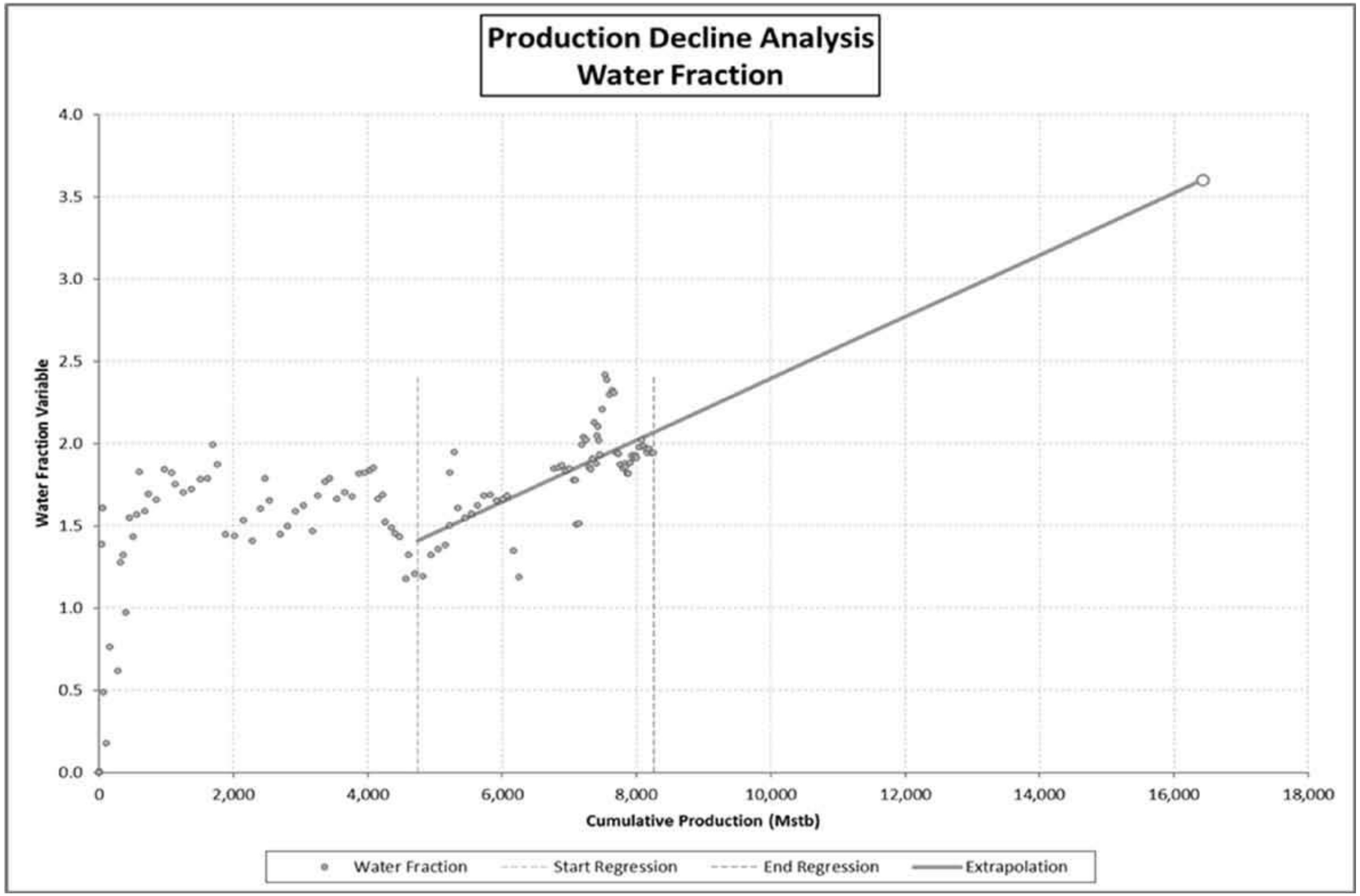


Figure E.9: **East Bunga Orkid WOR Analysis Plot**

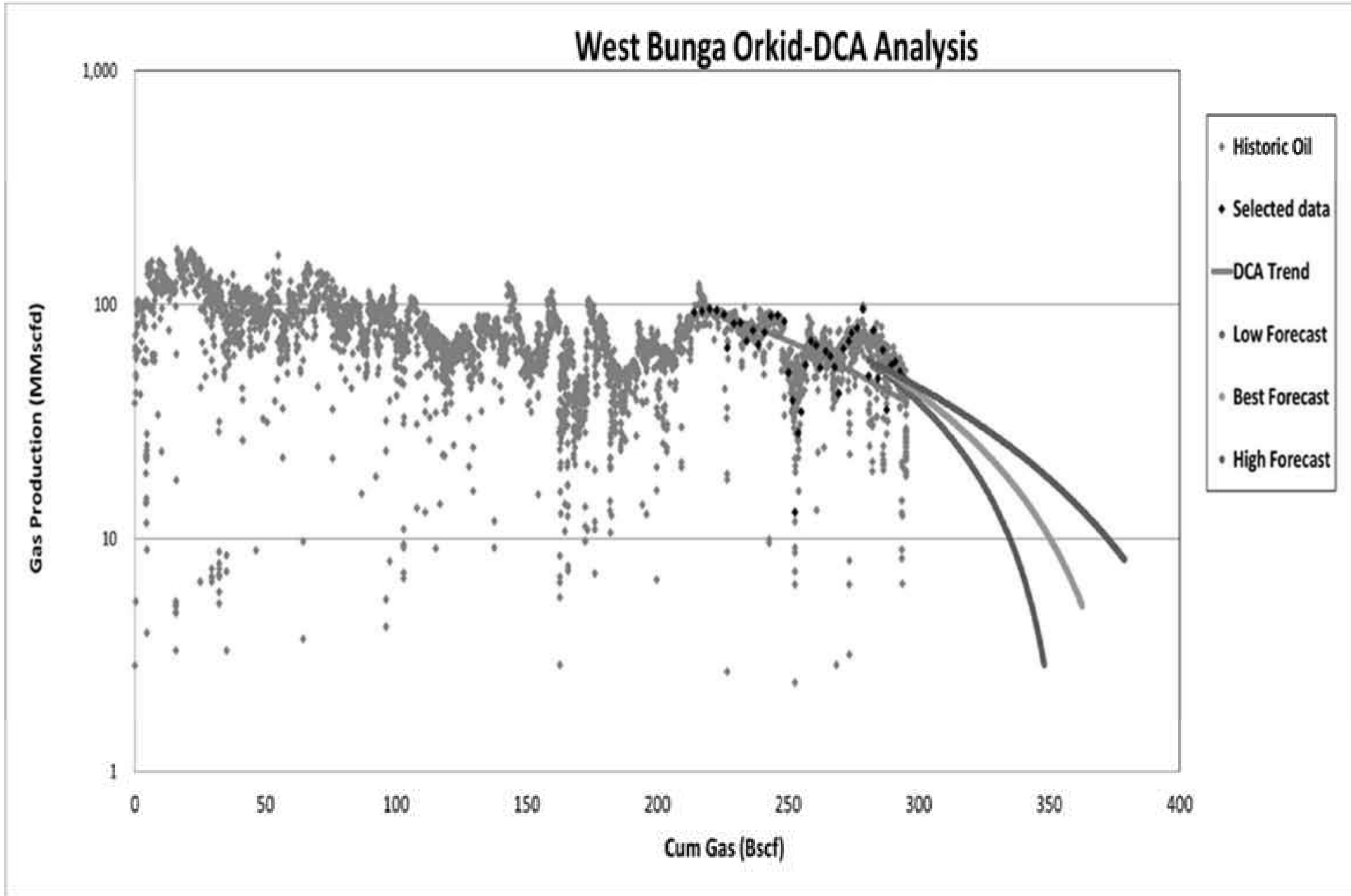


Figure E.10: West Bunga Orkid Gas DCA Plot

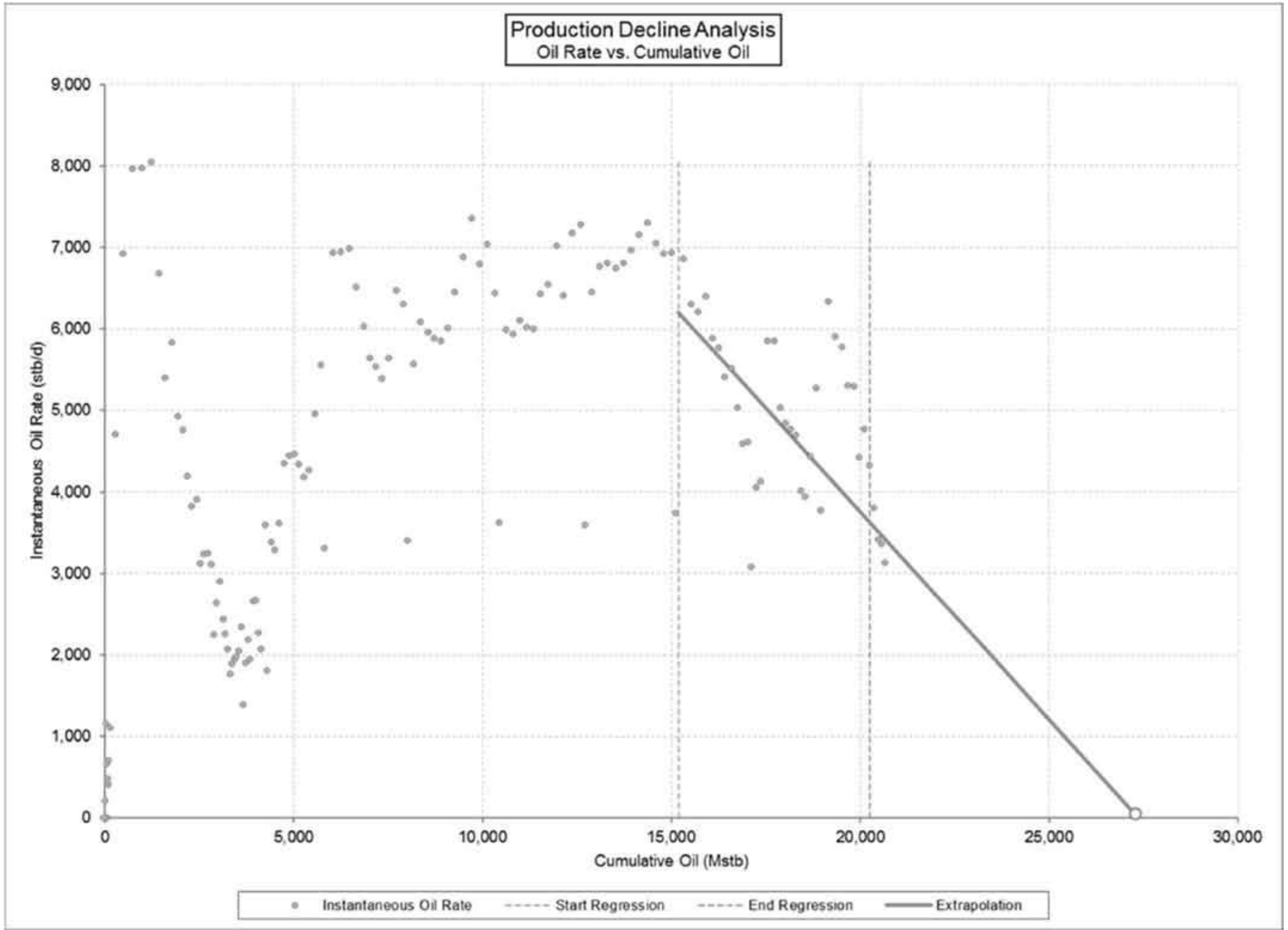


Figure E.11: West Bunga Orkid Oil DCA Plot

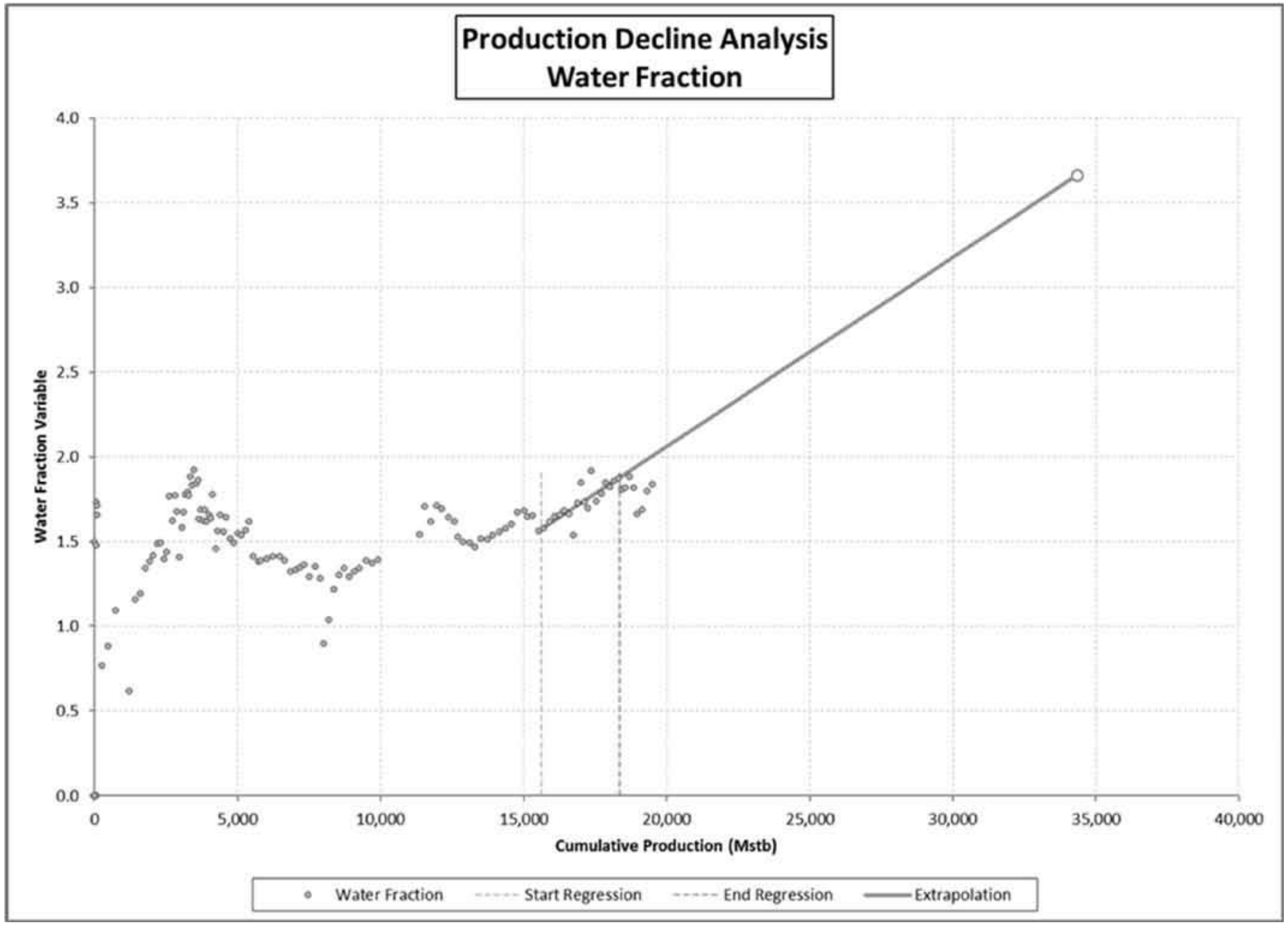


Figure E.12: West Bunga Orkid WOR Analysis Plot

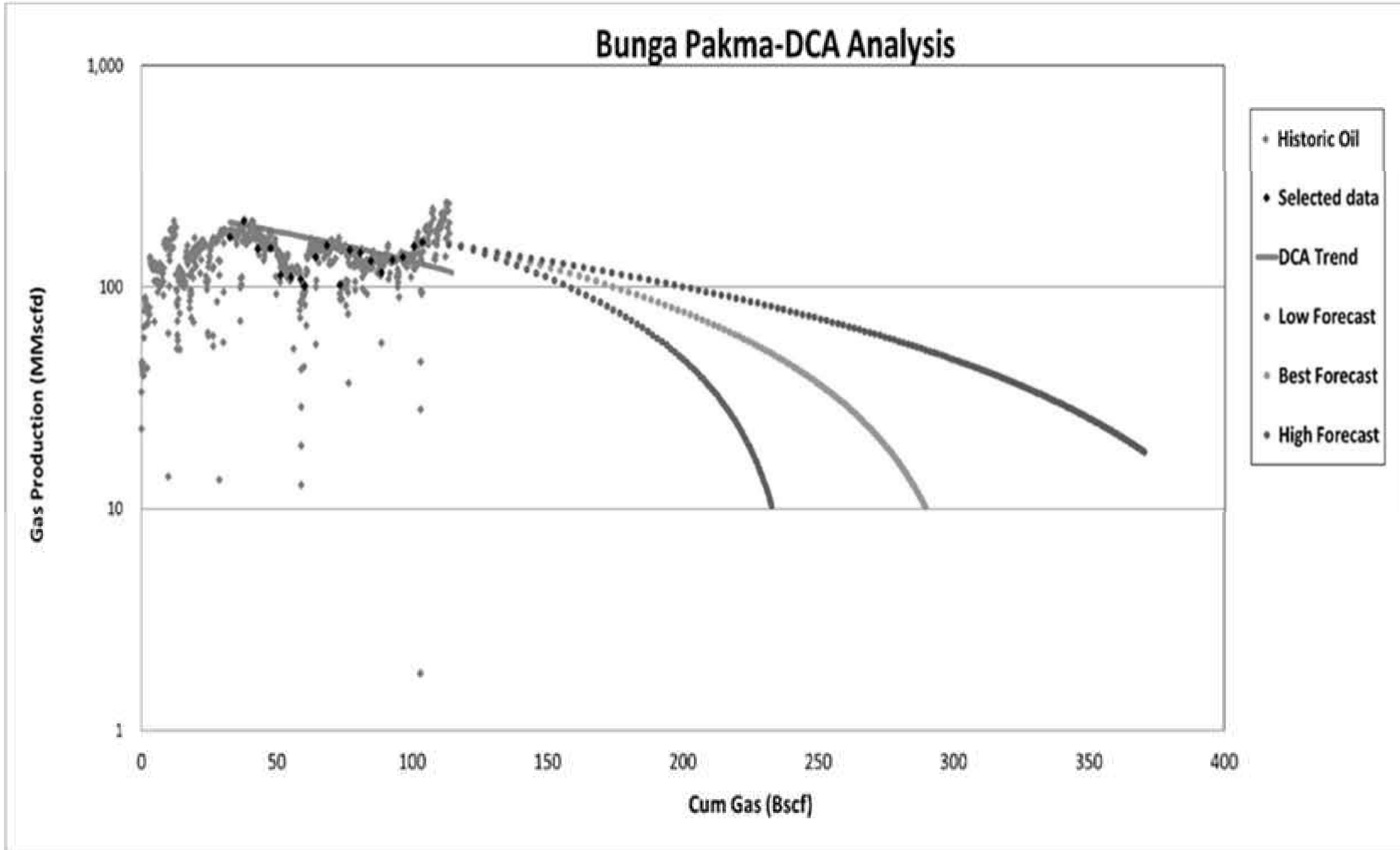


Figure E.13: Bunga Pakma Gas DCA Plot

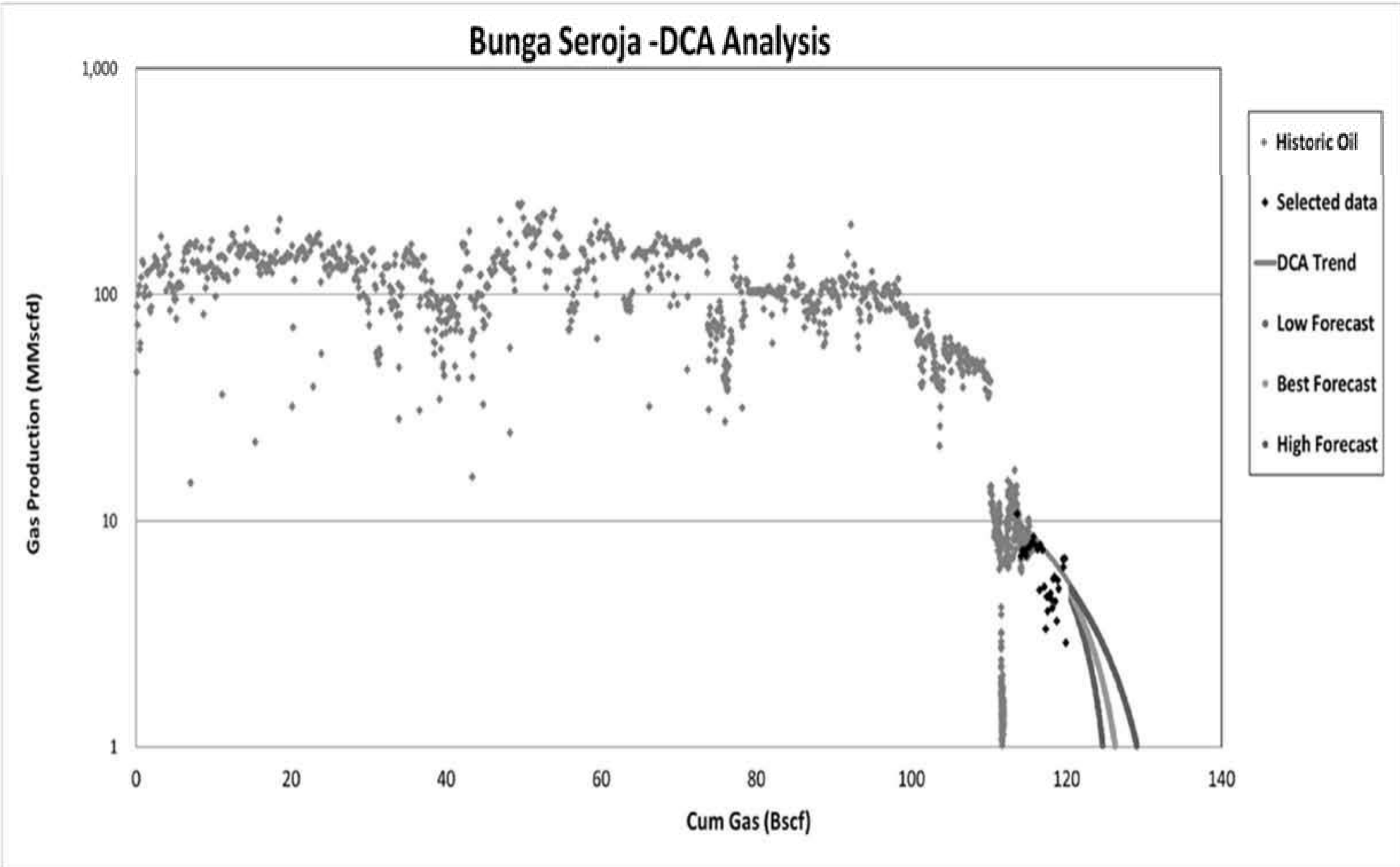


Figure E.14: Bunga Seroja Gas DCA Plot

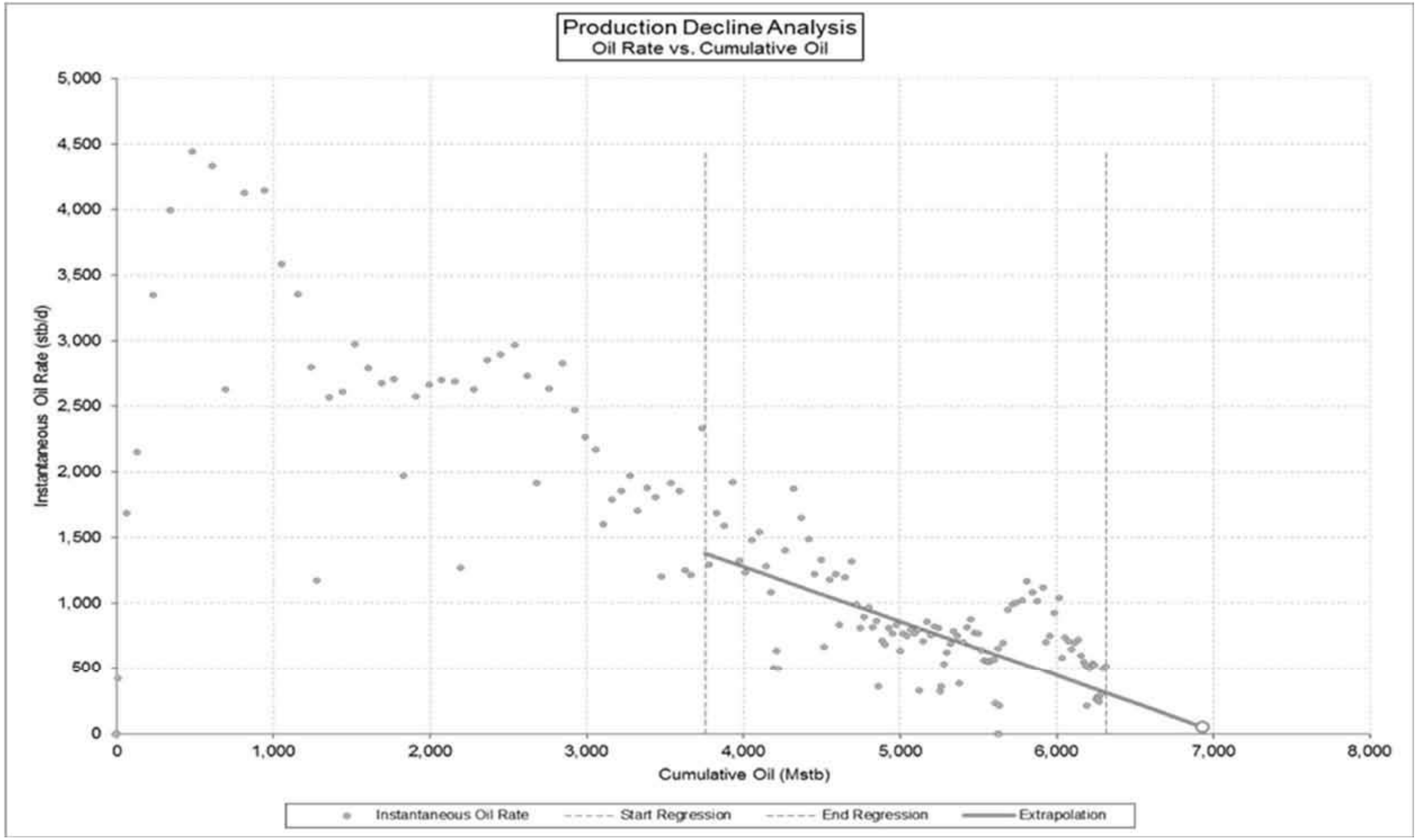


Figure E.15: Bunga Tulip Oil Rate DCA Plot

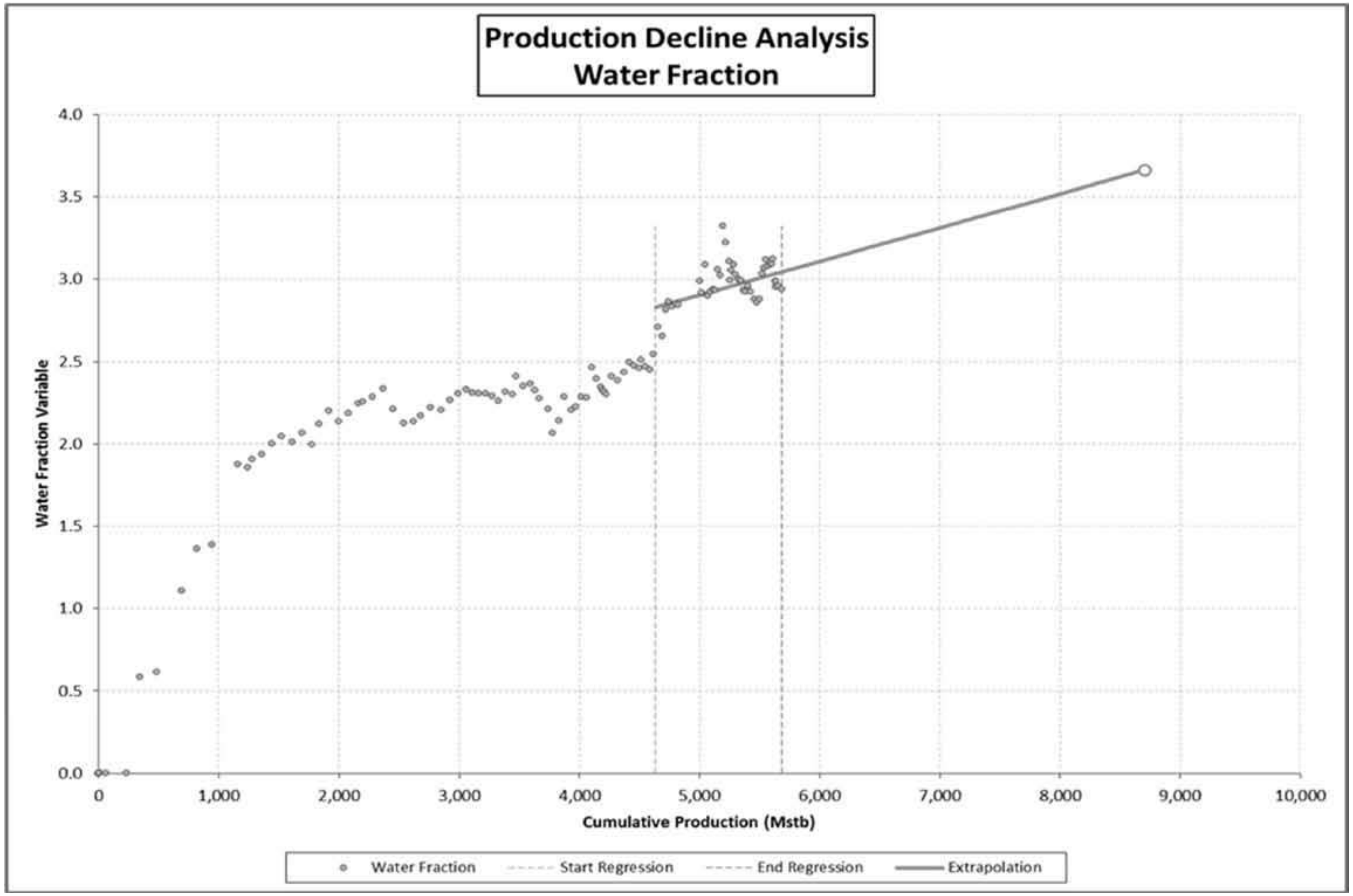


Figure E.16: Bunga Tulip WOR Analysis Plot

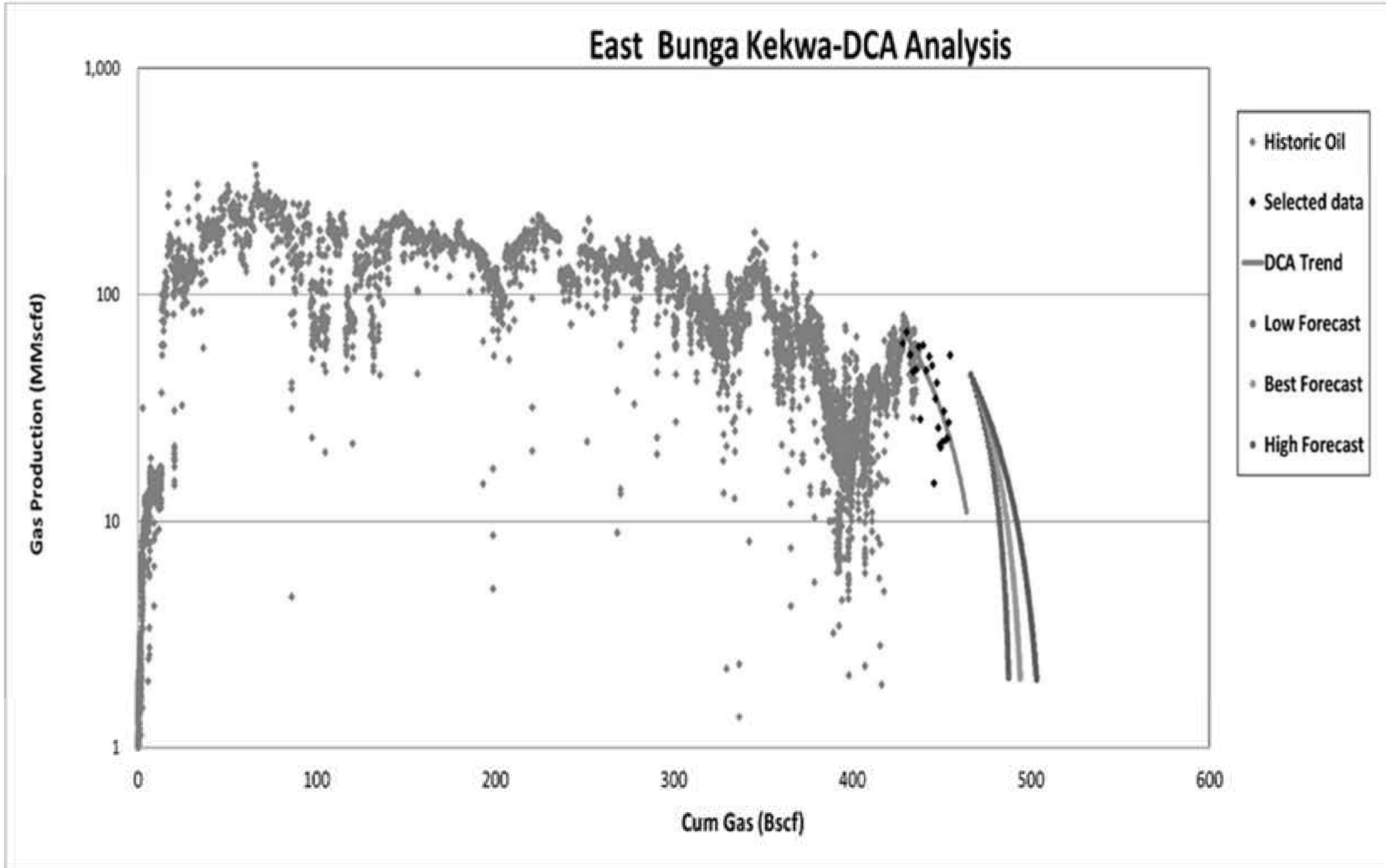


Figure E.17: East Bunga Kekwa Gas DCA Plot

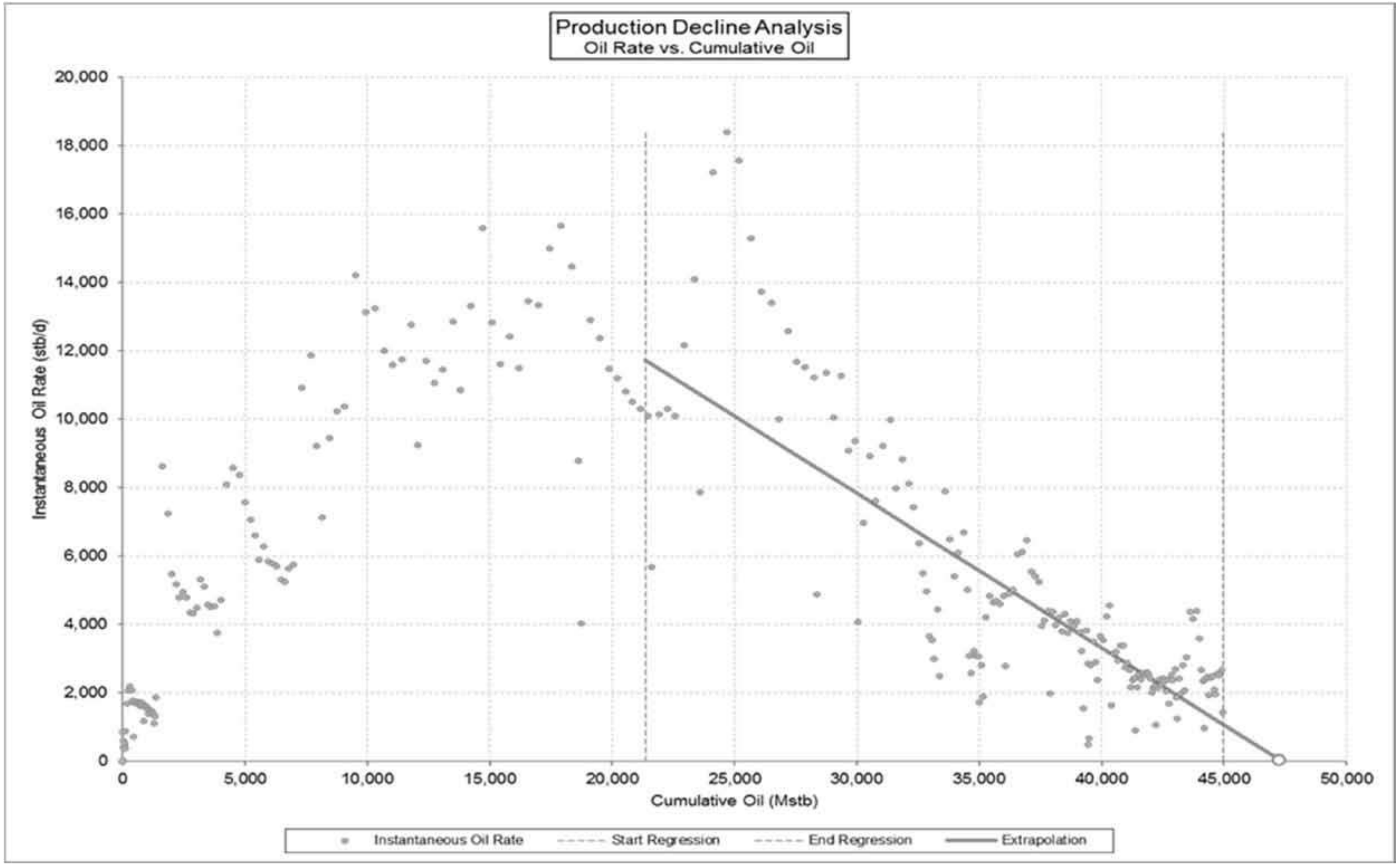


Figure E.18: East Bunga Kekwa Oil Rate DCA Plot

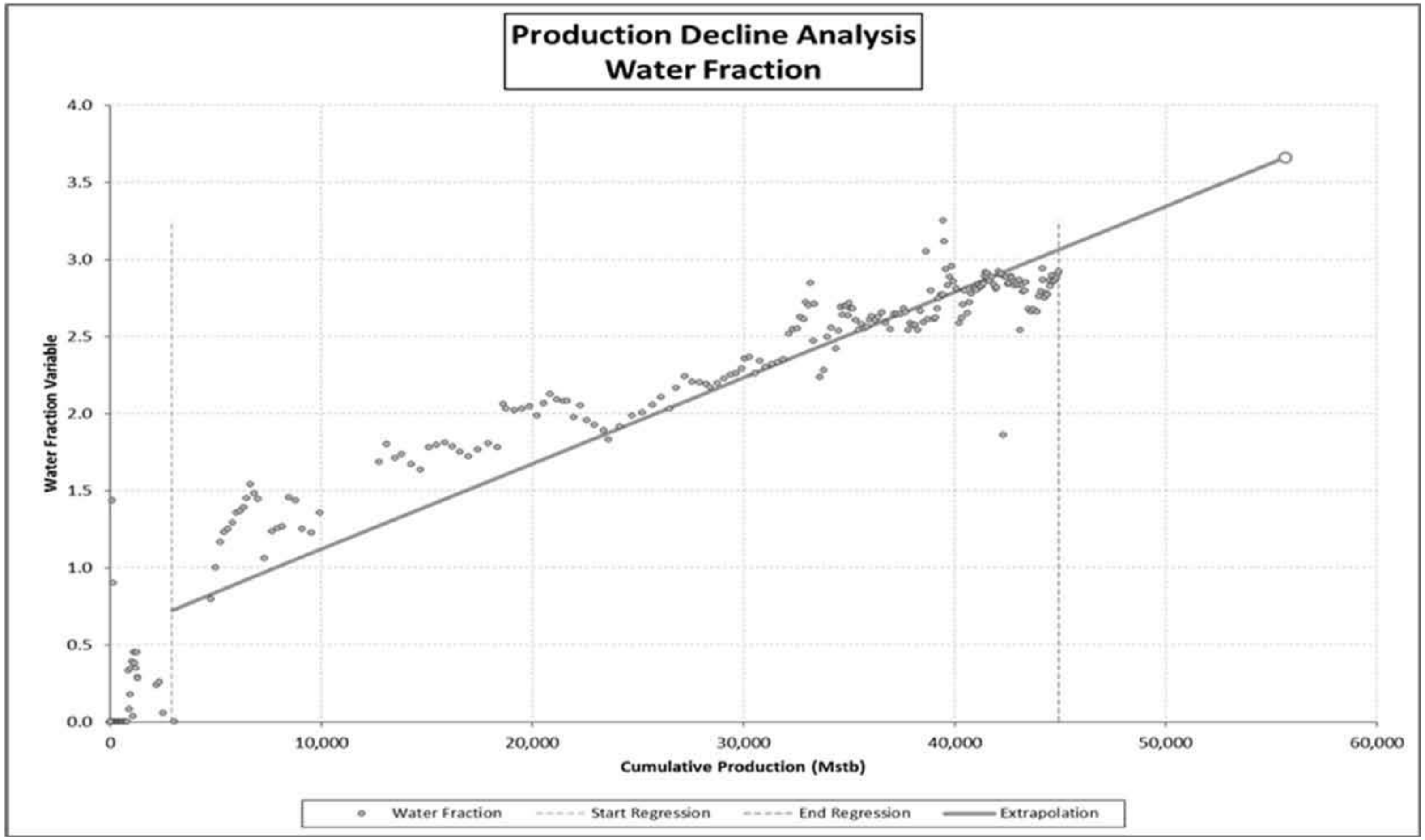


Figure E.19: East Bunga Kekwa WOR Analysis Plot

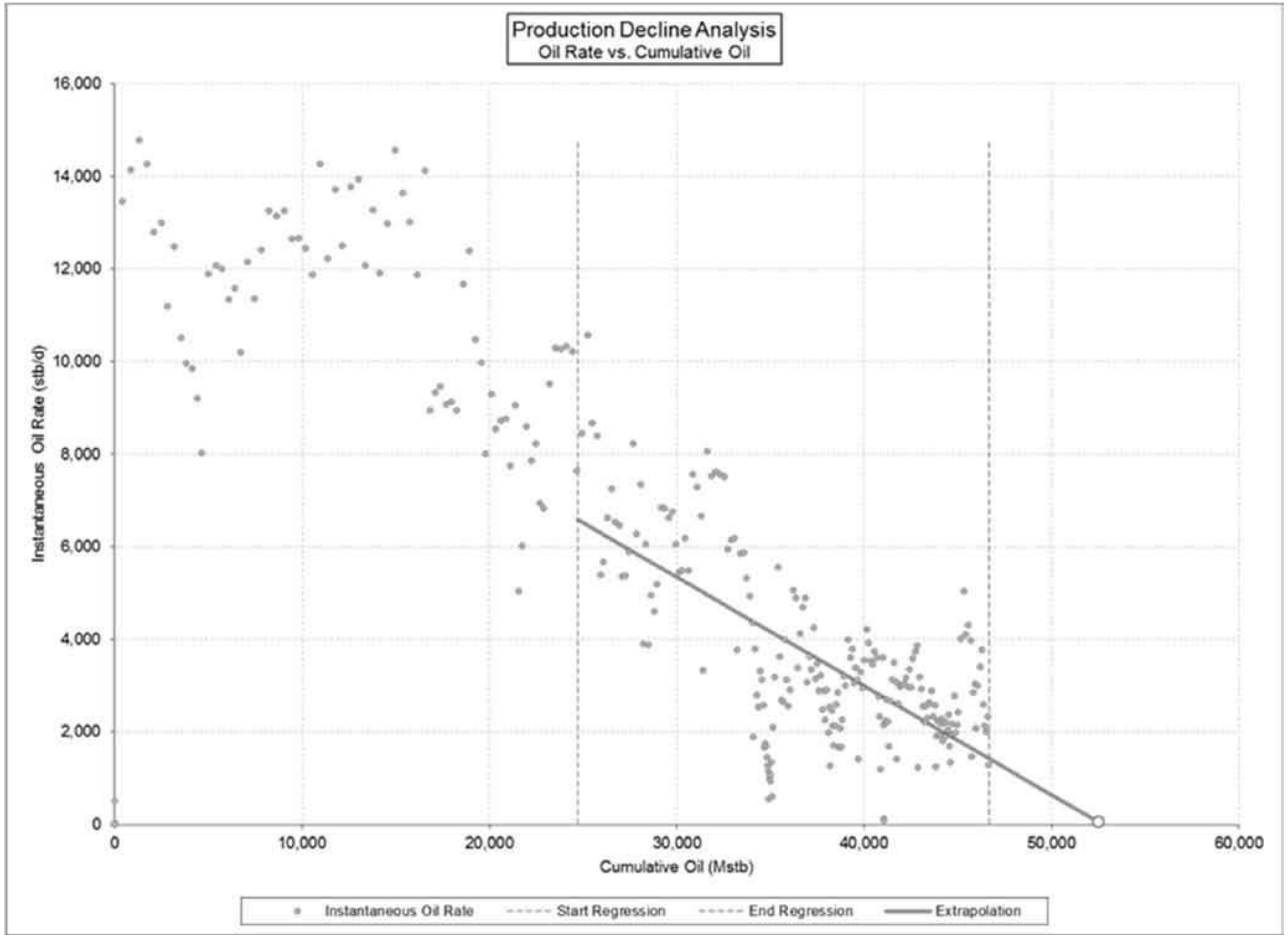


Figure E.20: West Bunga Kekwa Oil Rate DCA Plot

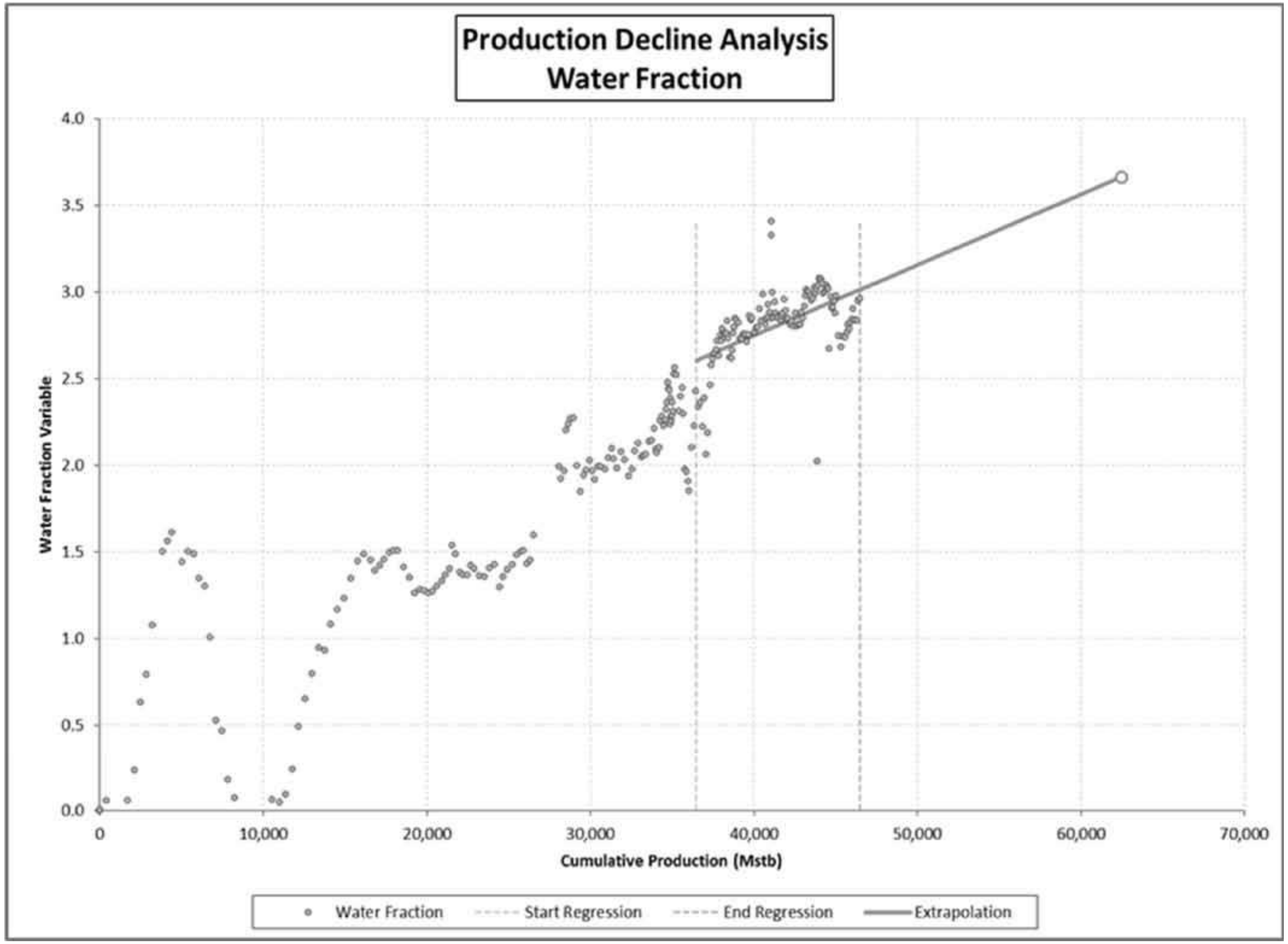


Figure E.21: West Bunga Kekwa WOR Analysis Plot

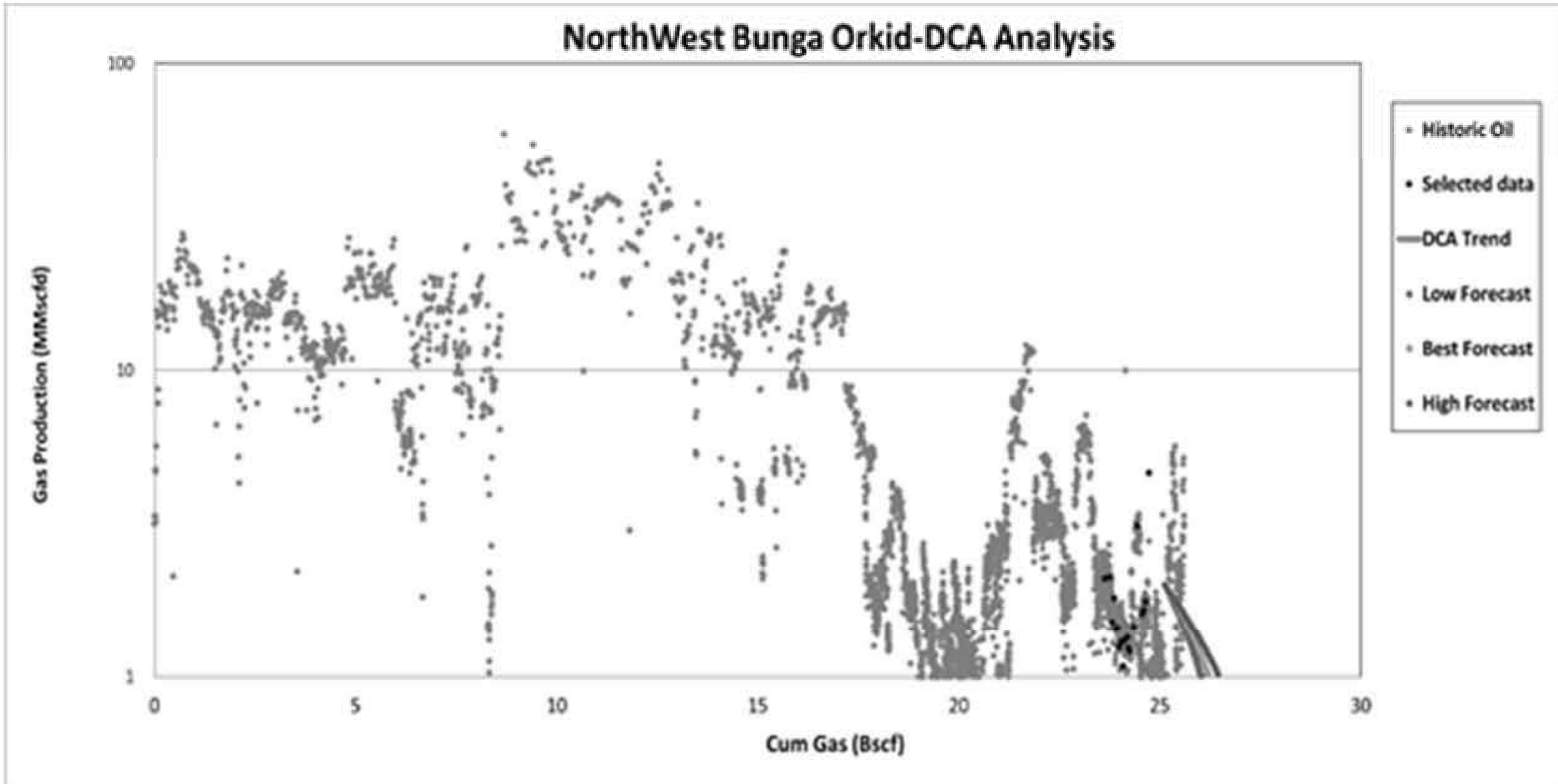


Figure E.22: Northwest Bunga Kekwa Gas DCA Plot

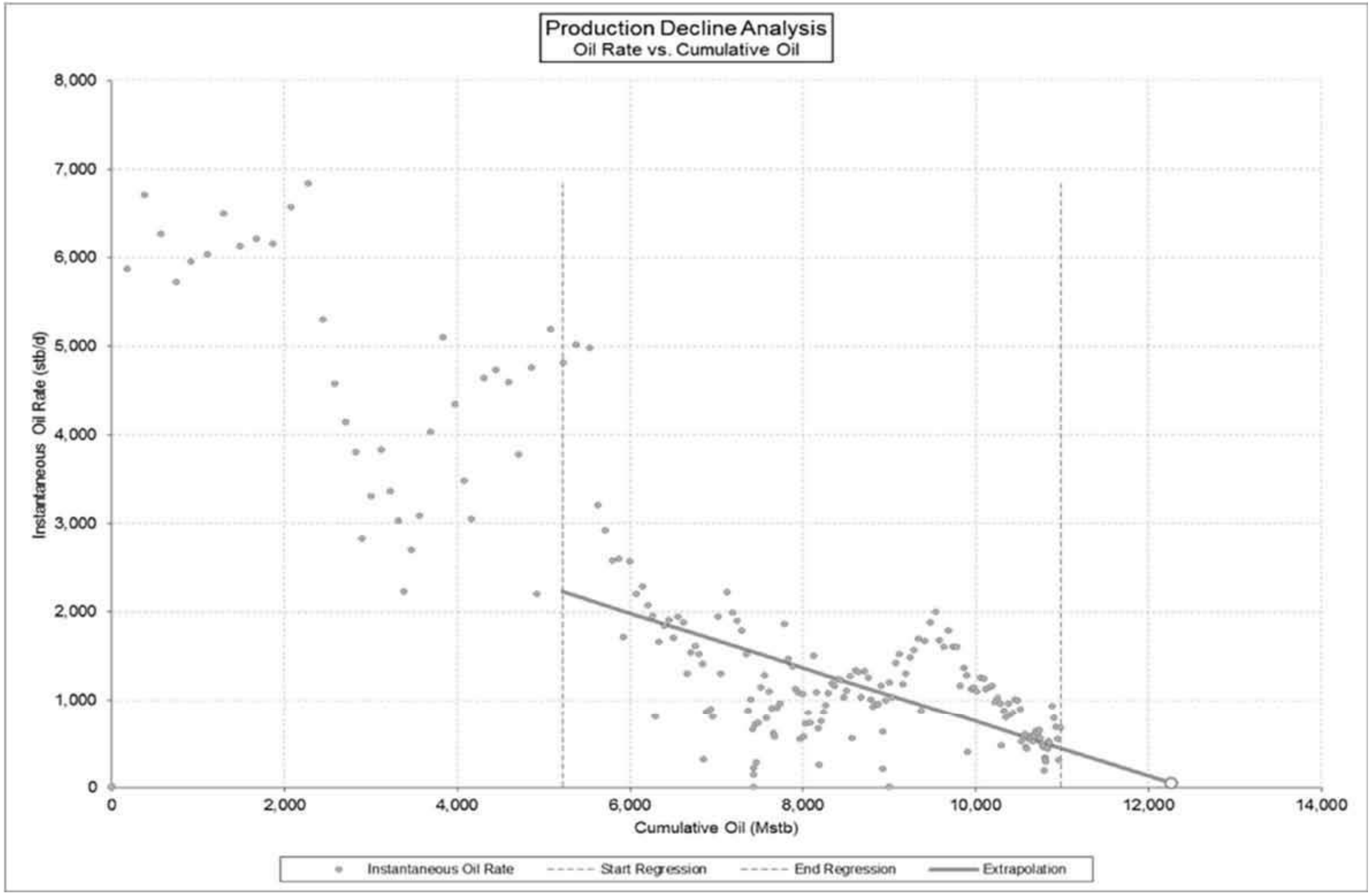


Figure E.23: Northwest Bunga Raya Oil Rate DCA Plot

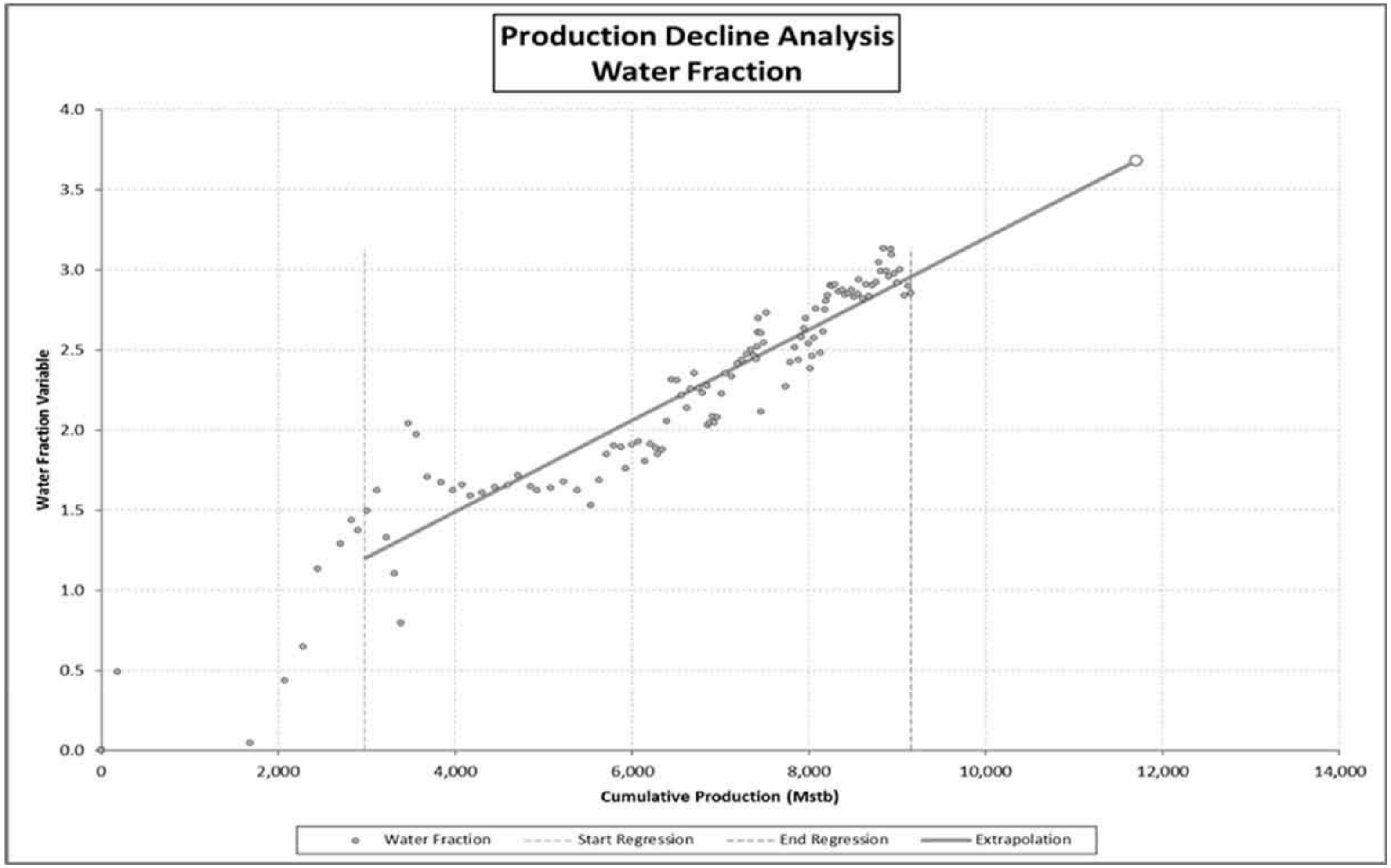


Figure E.24: Northwest Bunga Raya WOR Analysis Plot

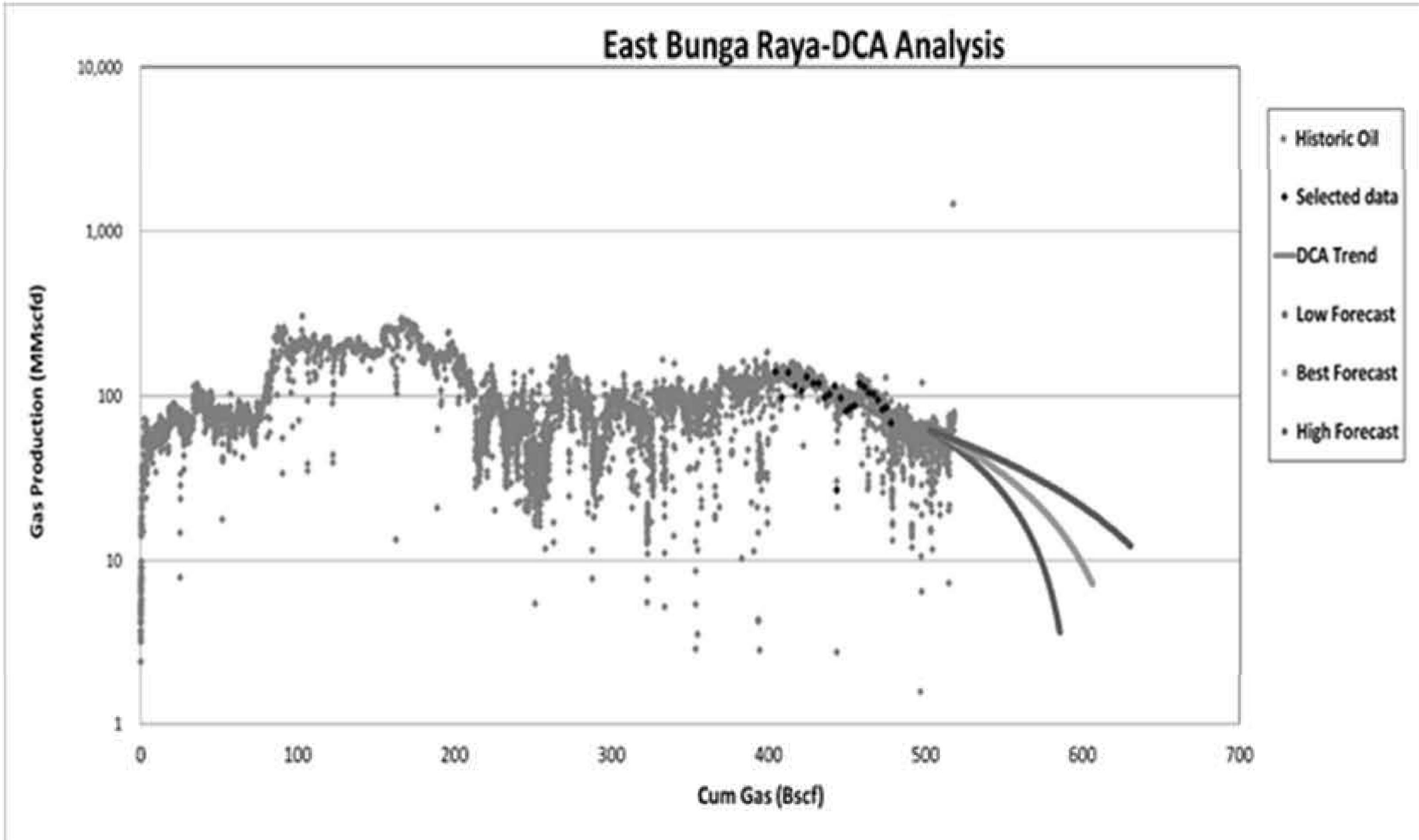


Figure E.25: East Bunga Raya Gas DCA Plot

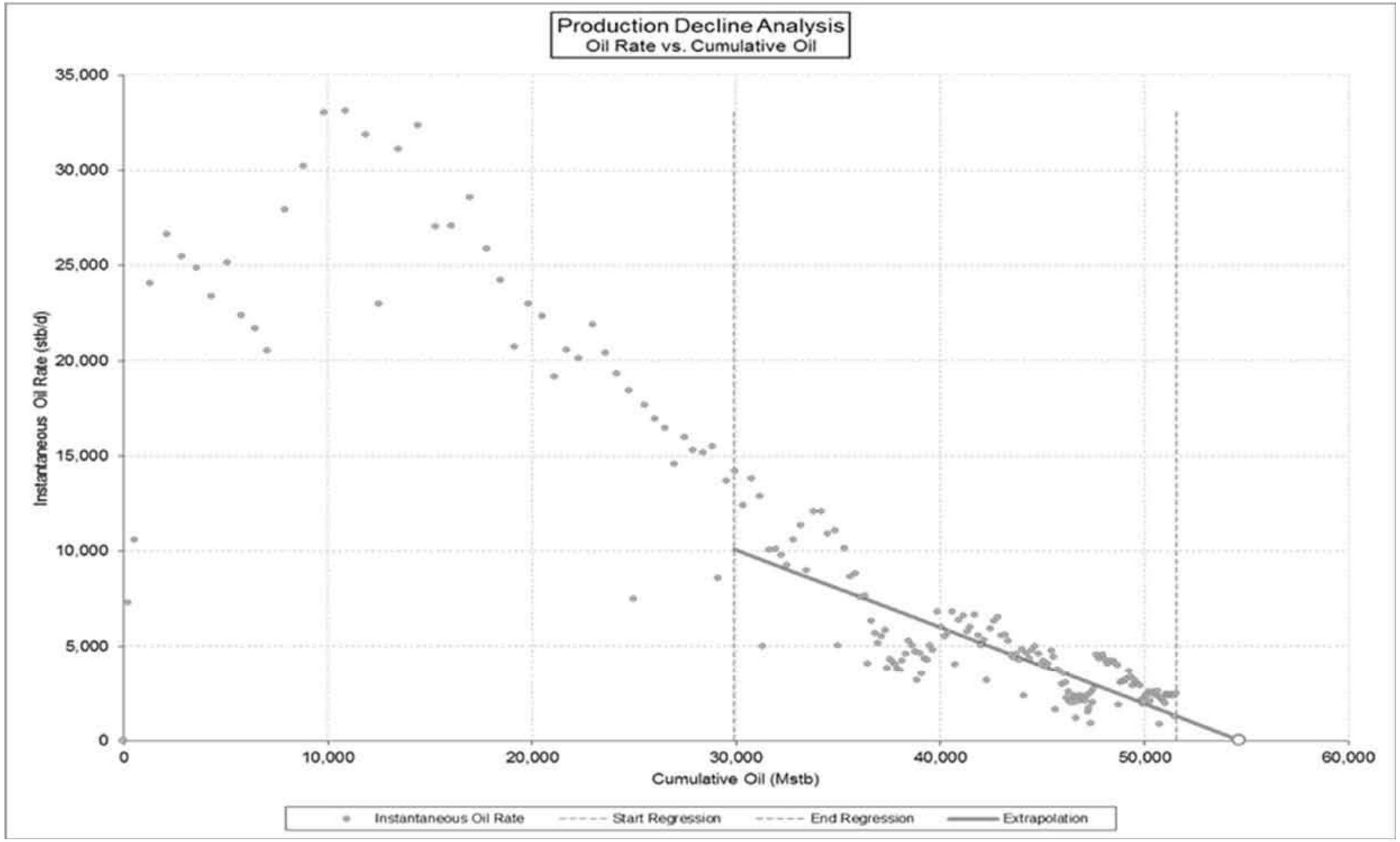


Figure E.26: East Bunga Raya Oil DCA Plot

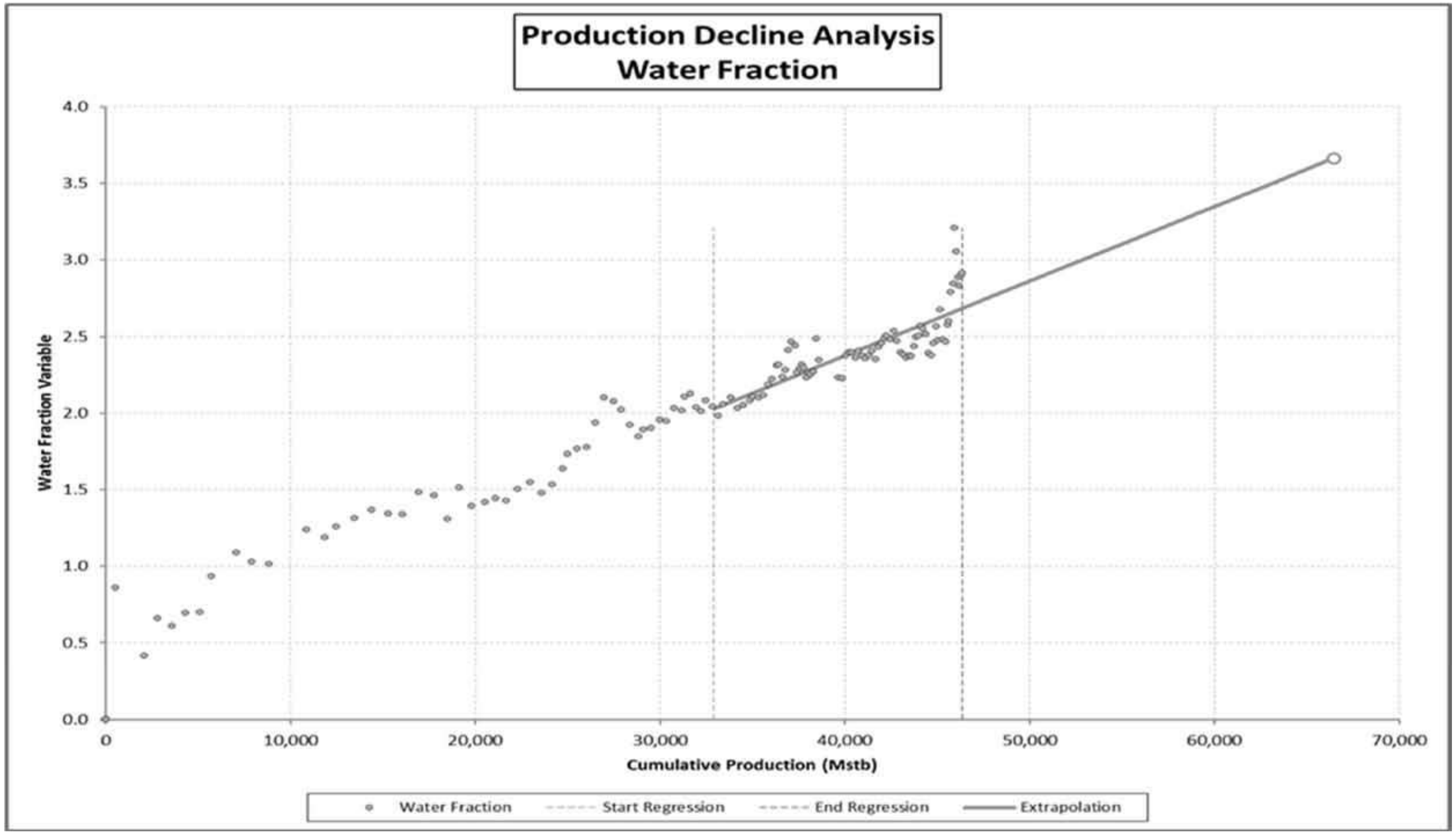


Figure E.27: East Bunga Raya WOR Analysis Plot

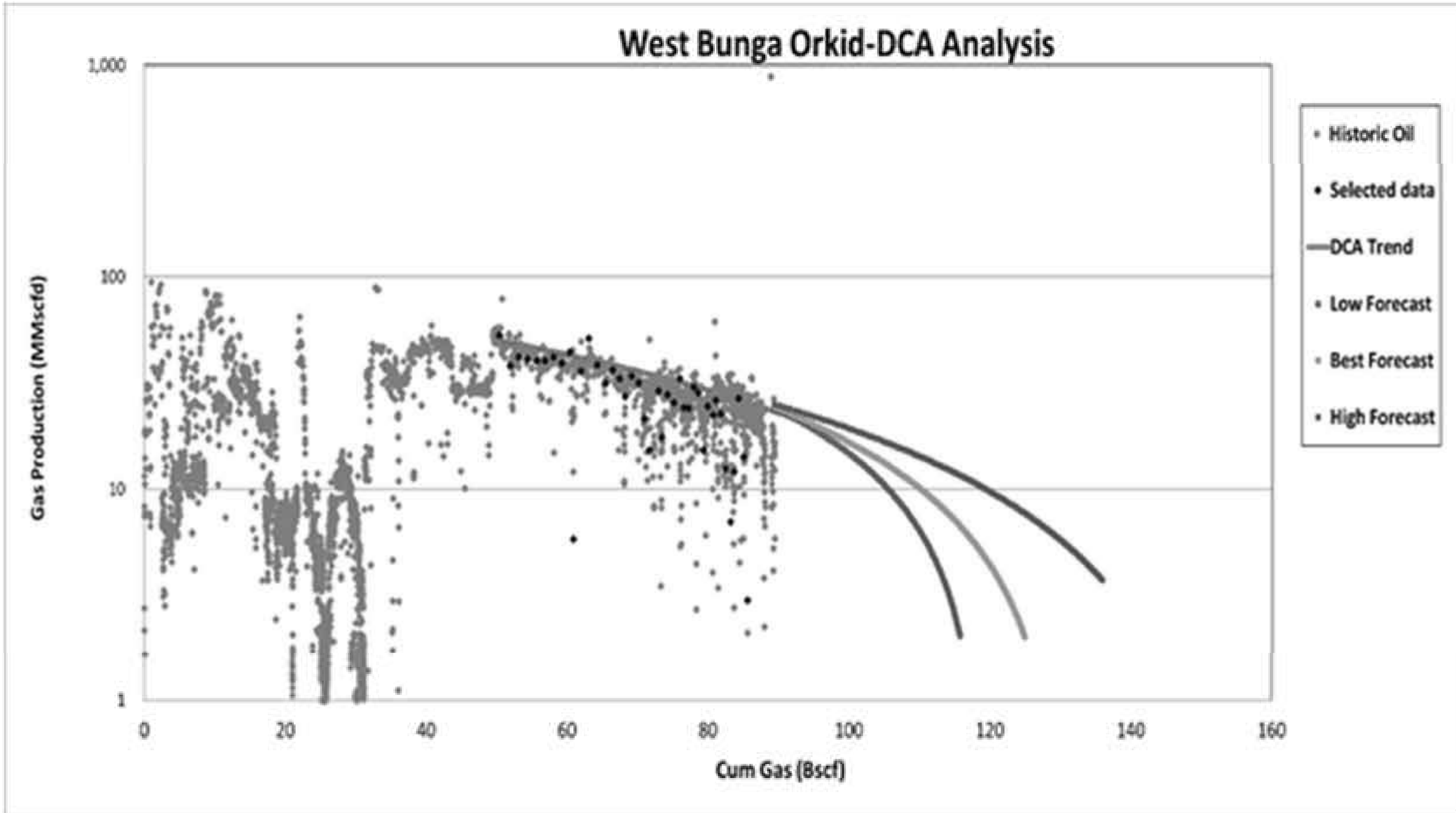


Figure E.28: West Bunga Raya Gas DCA Plot

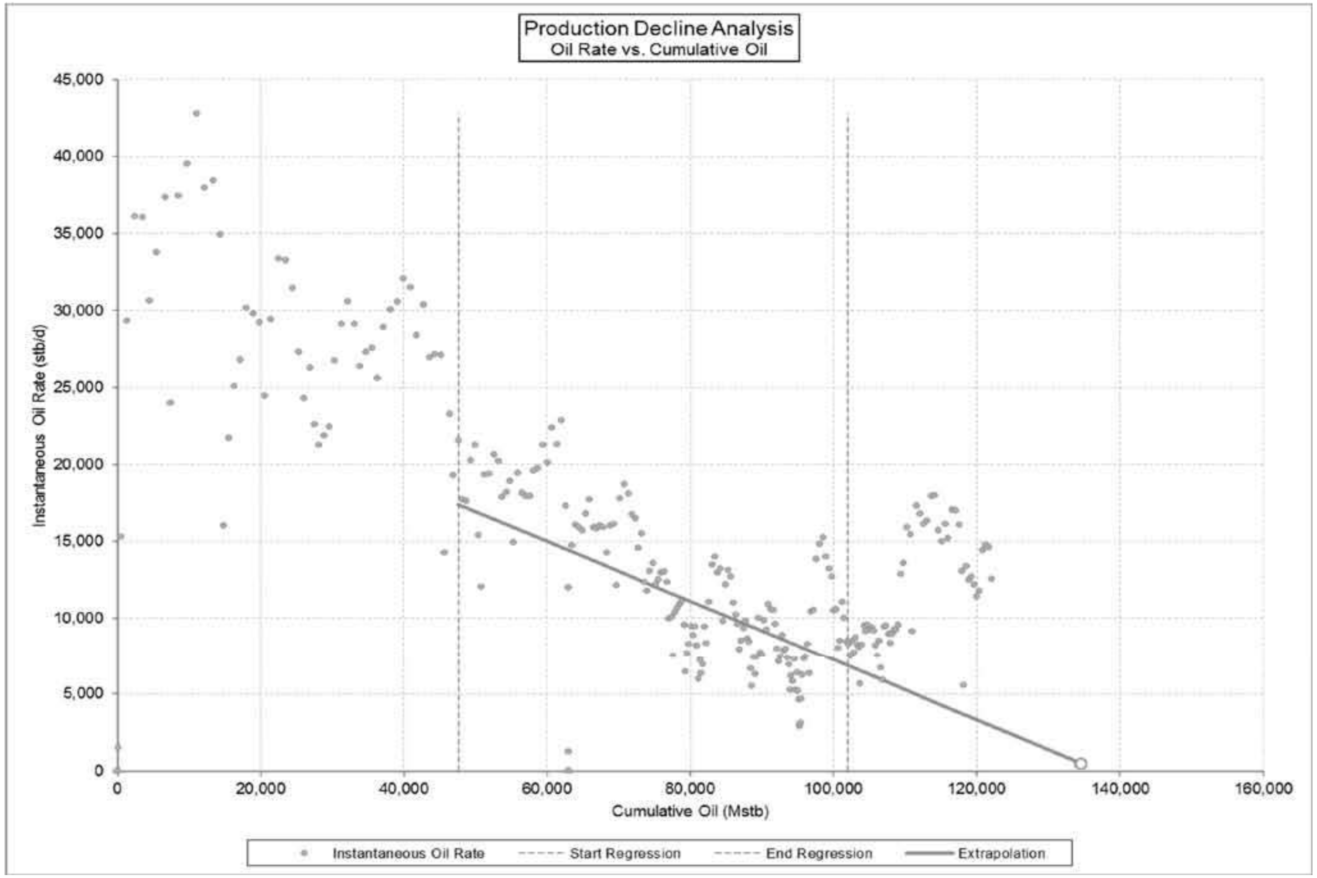


Figure E.29: Kinabalu Main Oil DCA Plot

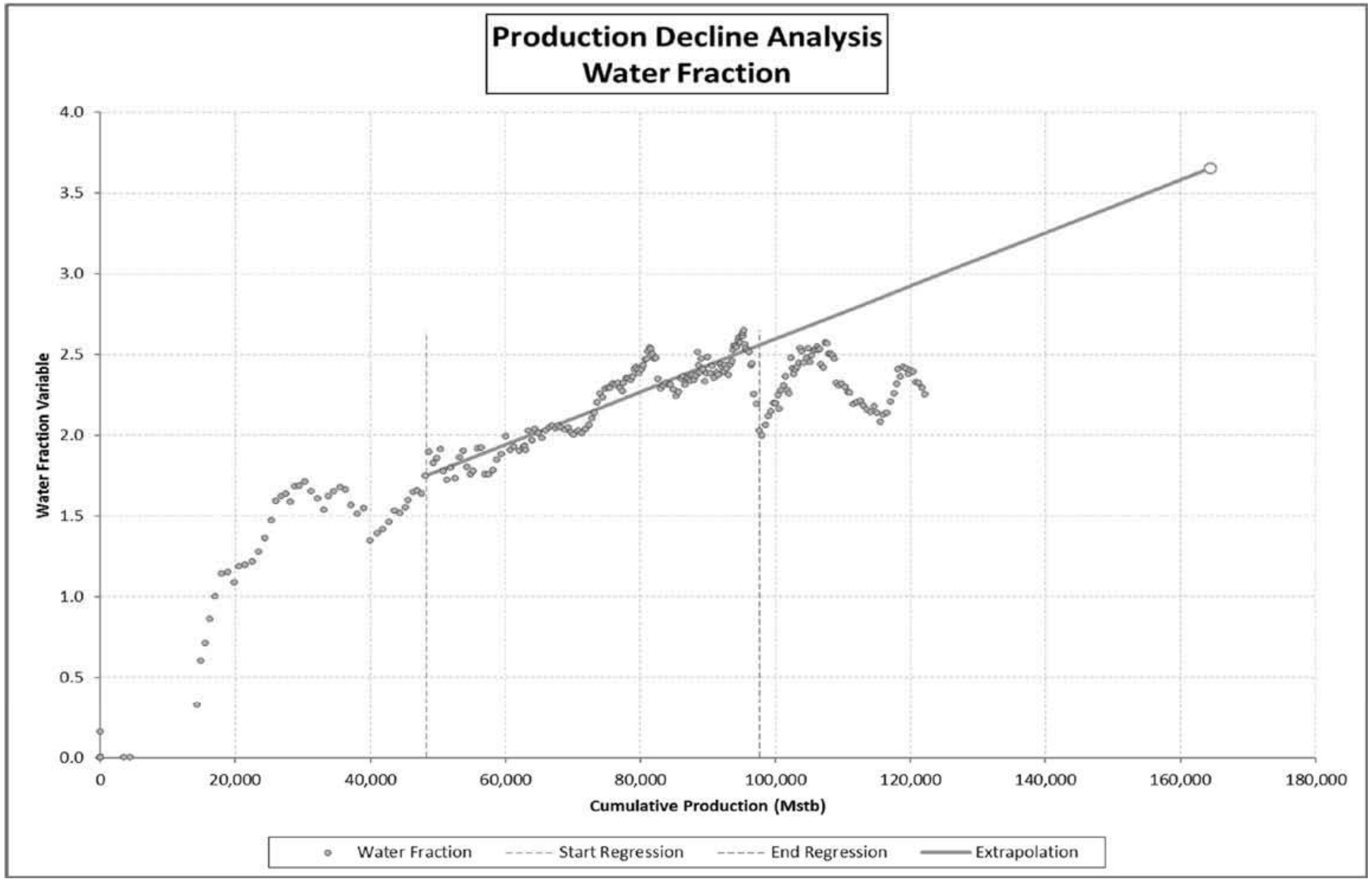


Figure E.30: Kinabalu Main WOR Analysis Plot

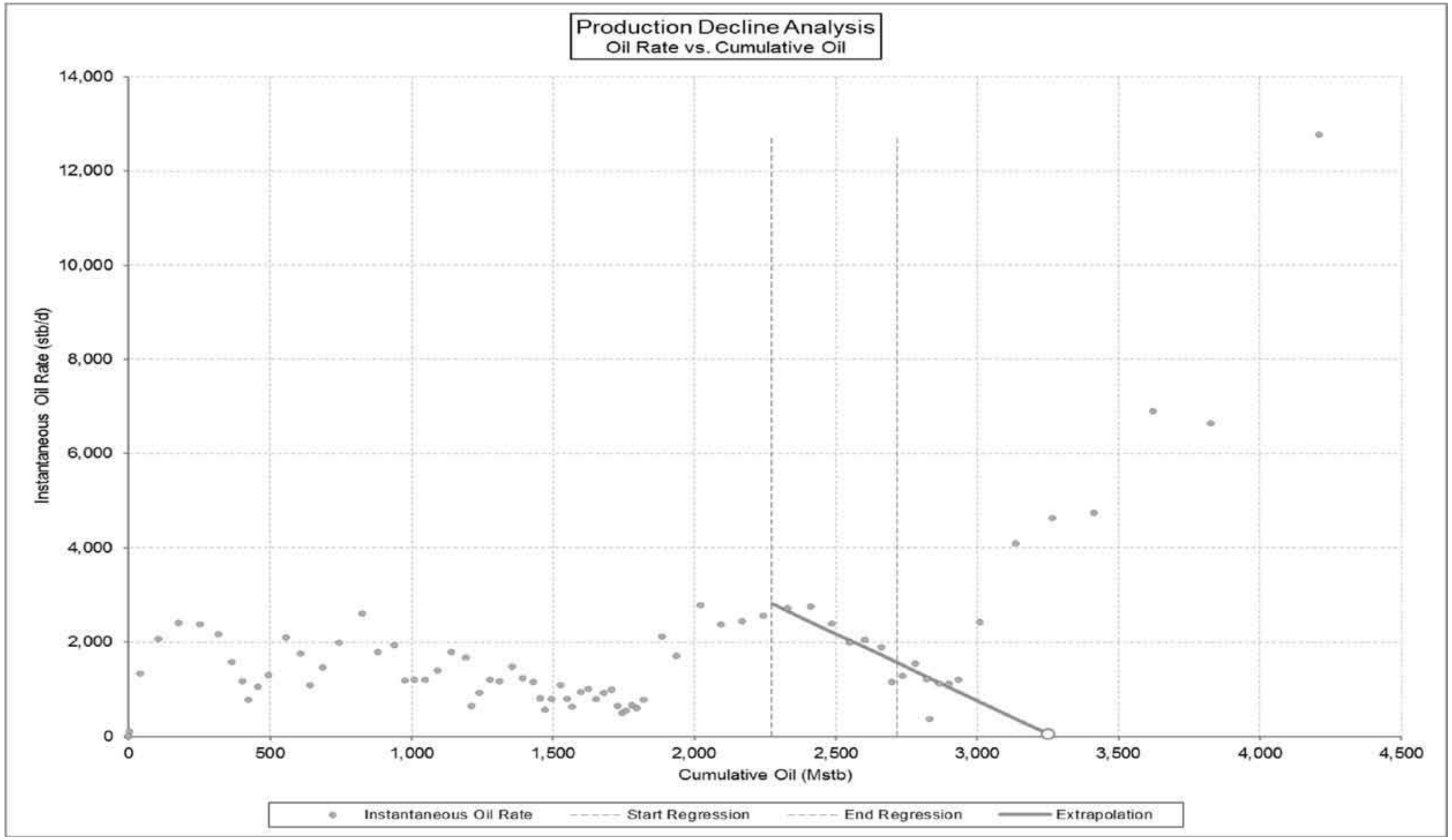


Figure E.31: Kinabalu East Oil DCA Plot

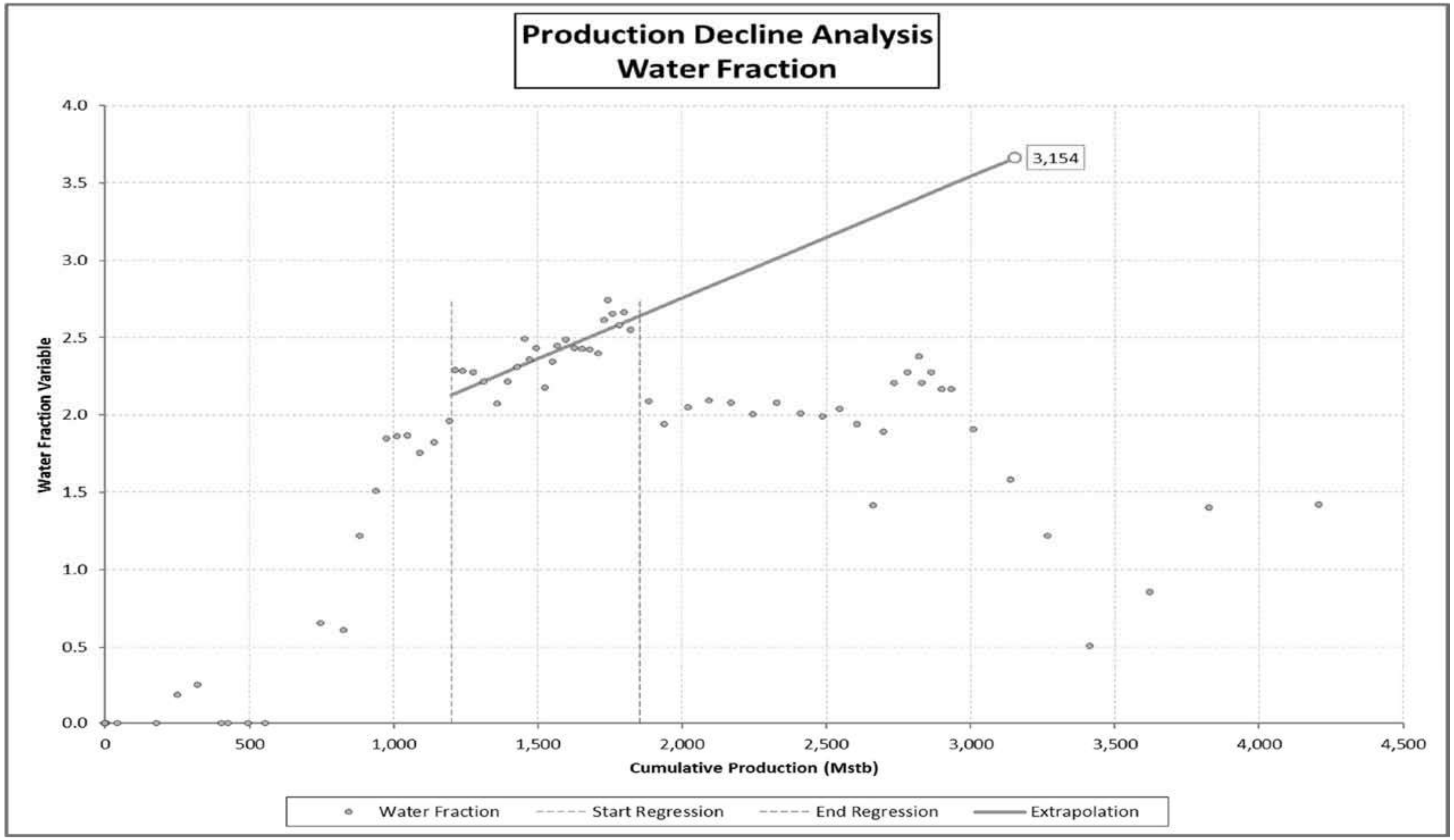


Figure E.32: Kinabalu East WOR Analysis Plot

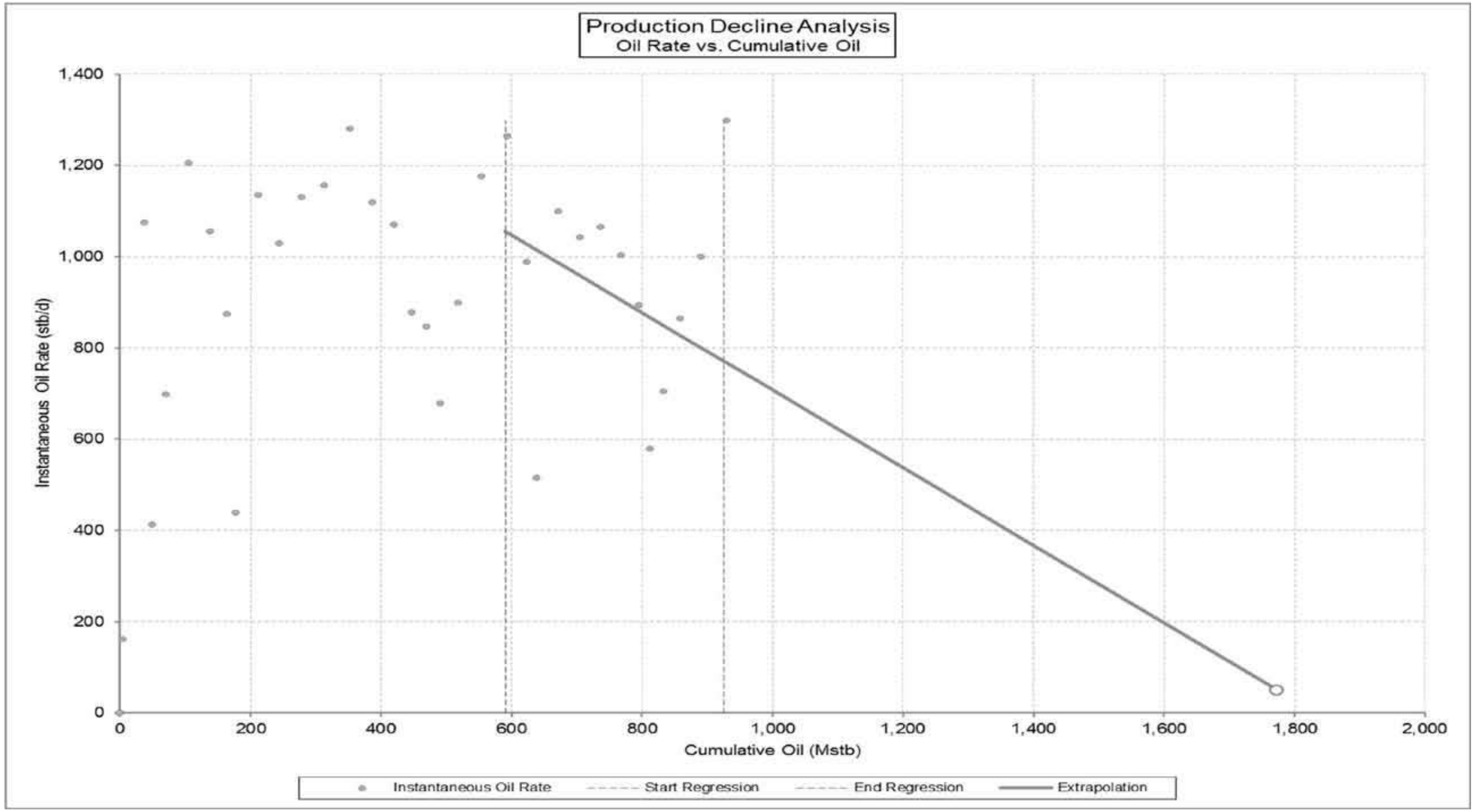


Figure E.33: Kinabalu Far East Oil DCA Plot

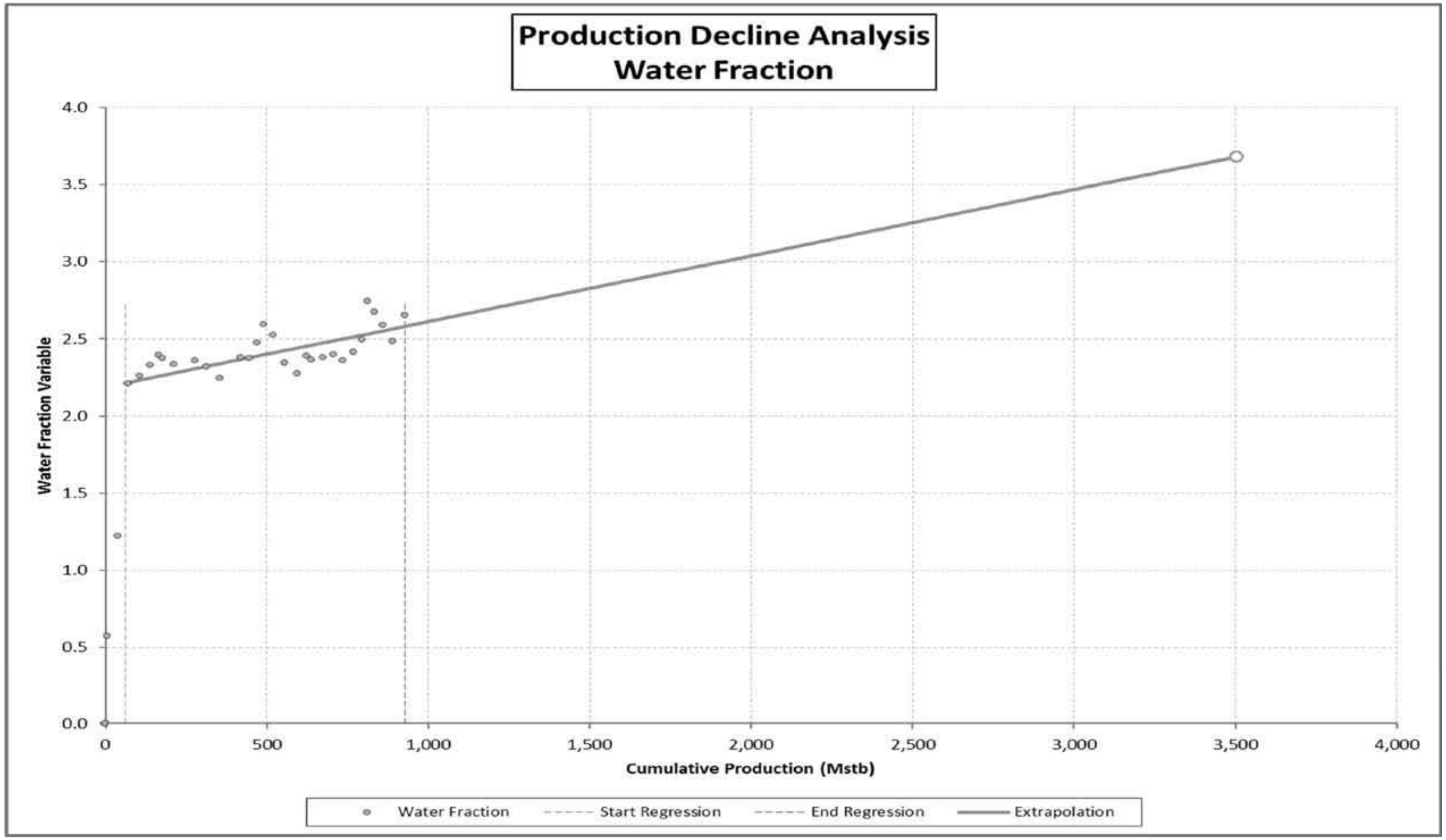


Figure E.34: Kinabalu Far East WOR Analysis Plot

Appendix F
Production Forecast Plots

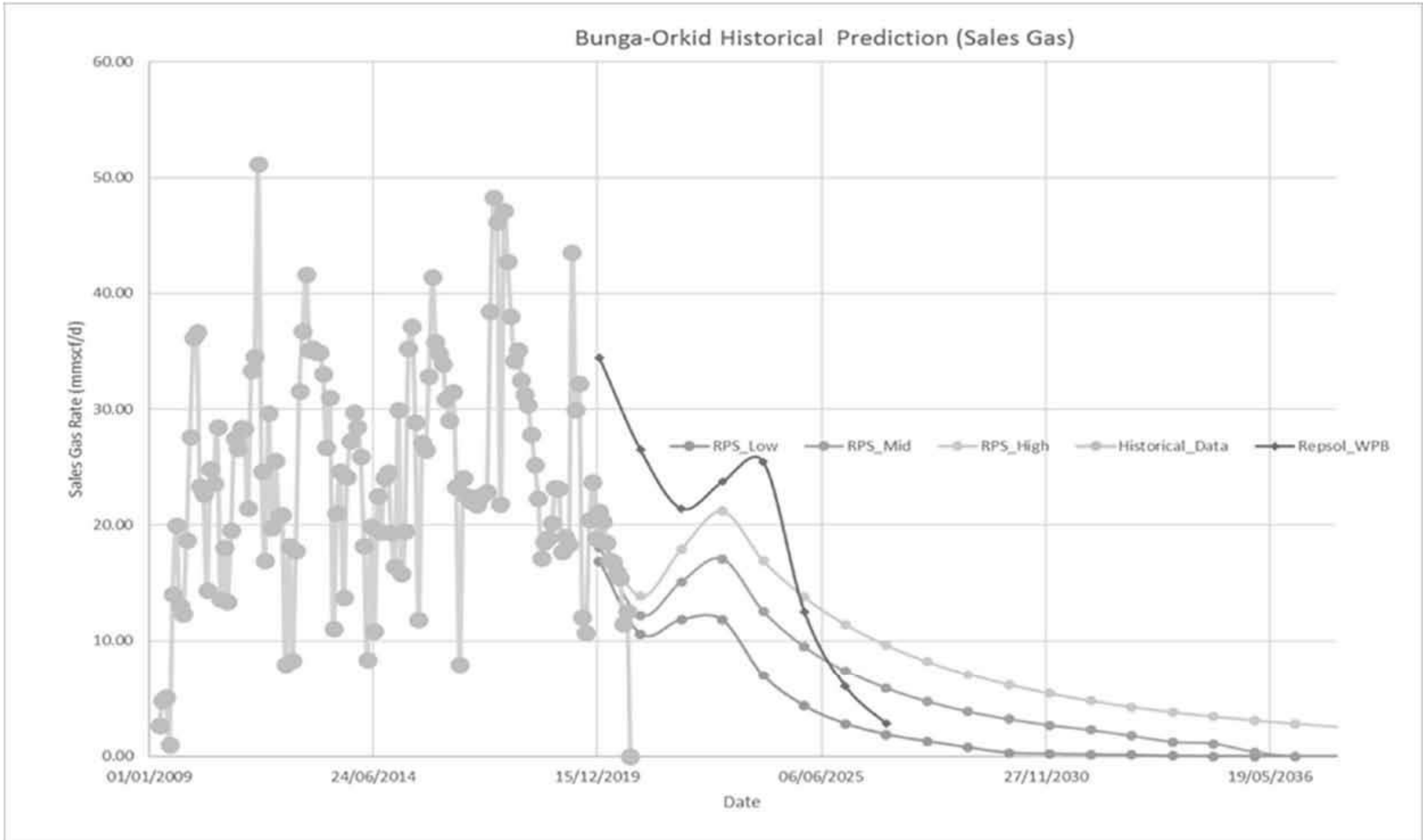


Figure F.1: Bunga Orkid Sales Gas Forecast Plot

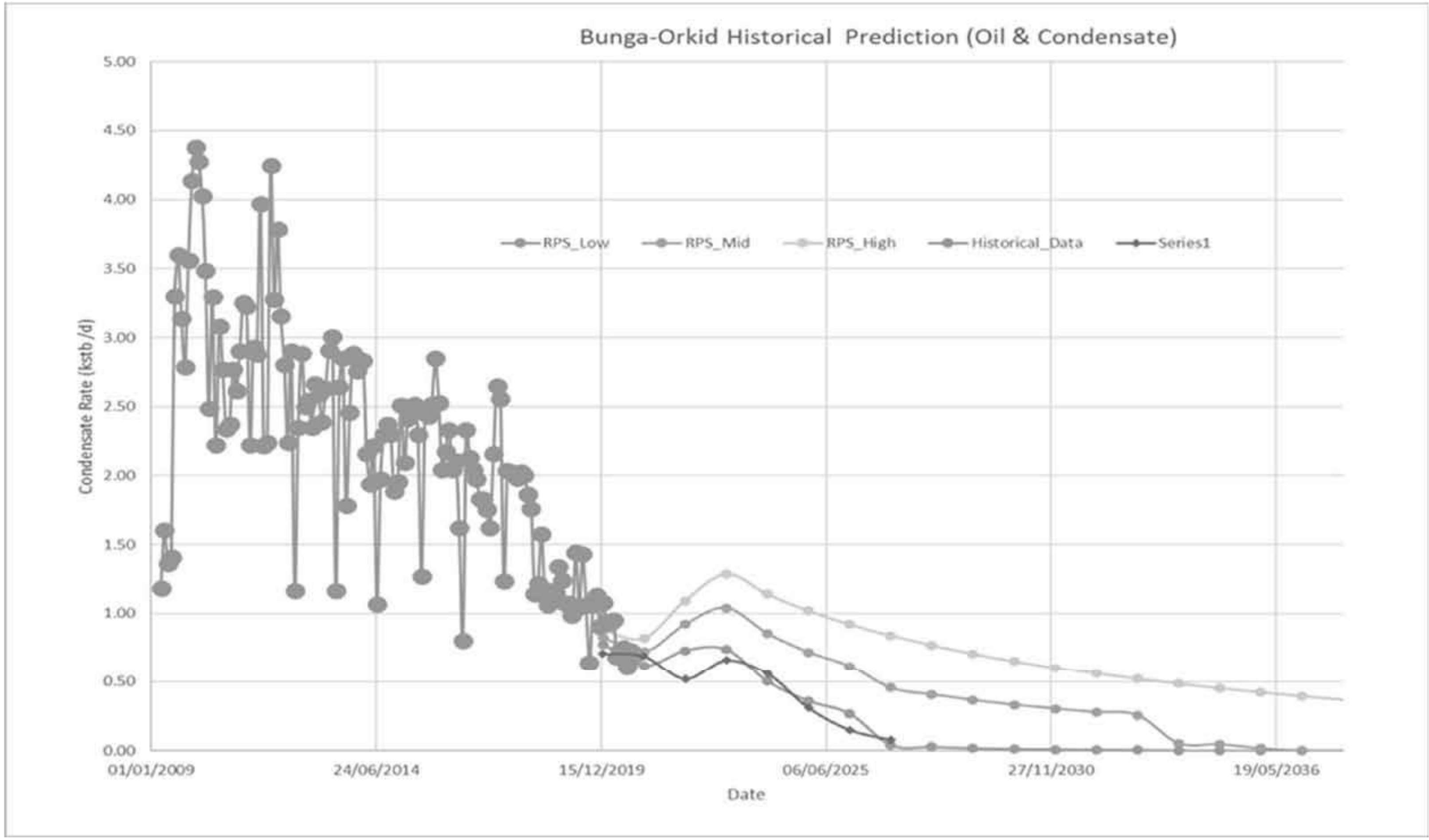


Figure F.2: Bunga Orkid Oil & Condensate Forecast Plot

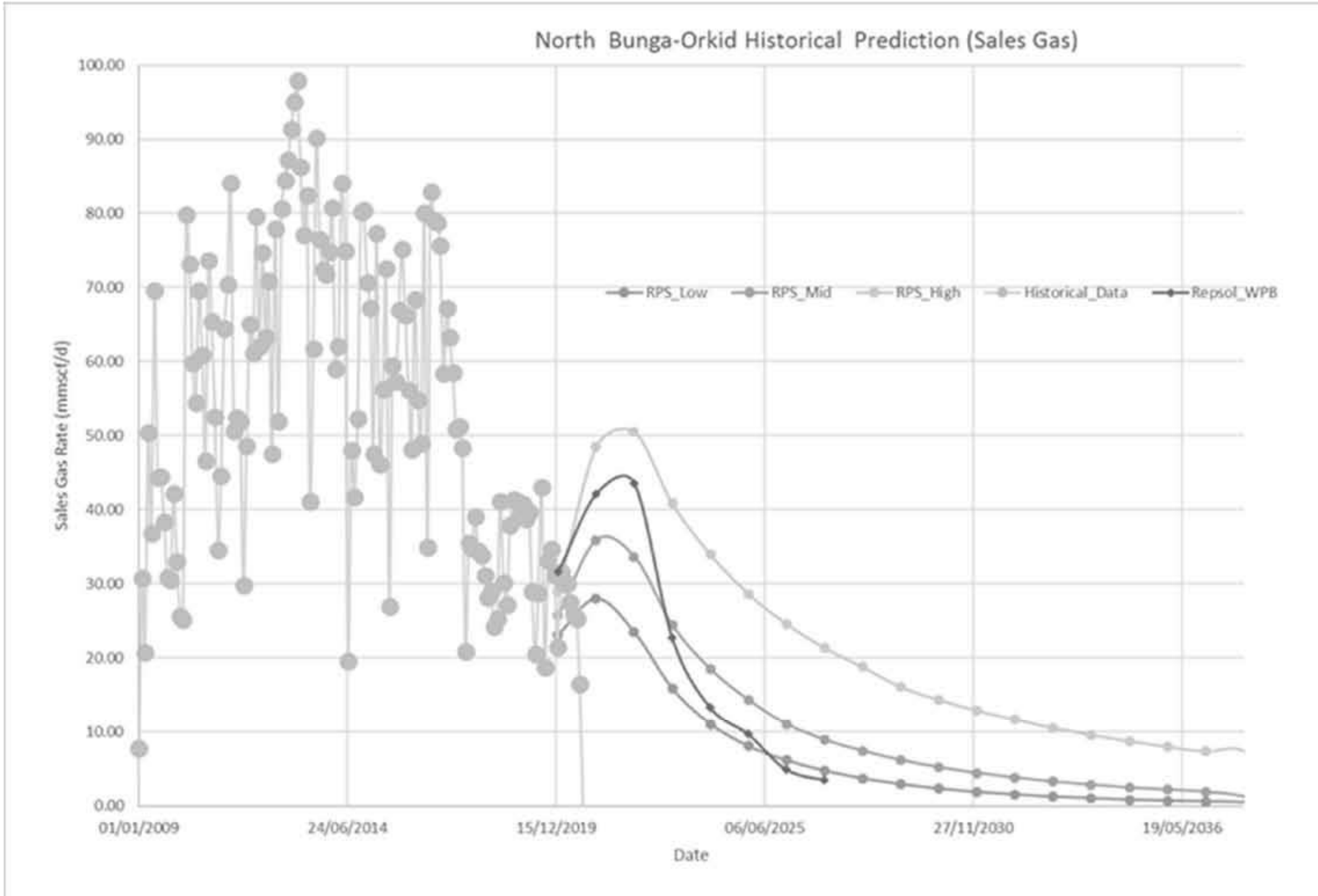


Figure F.3: North Bunga Orkid Sales Gas Forecast Plot

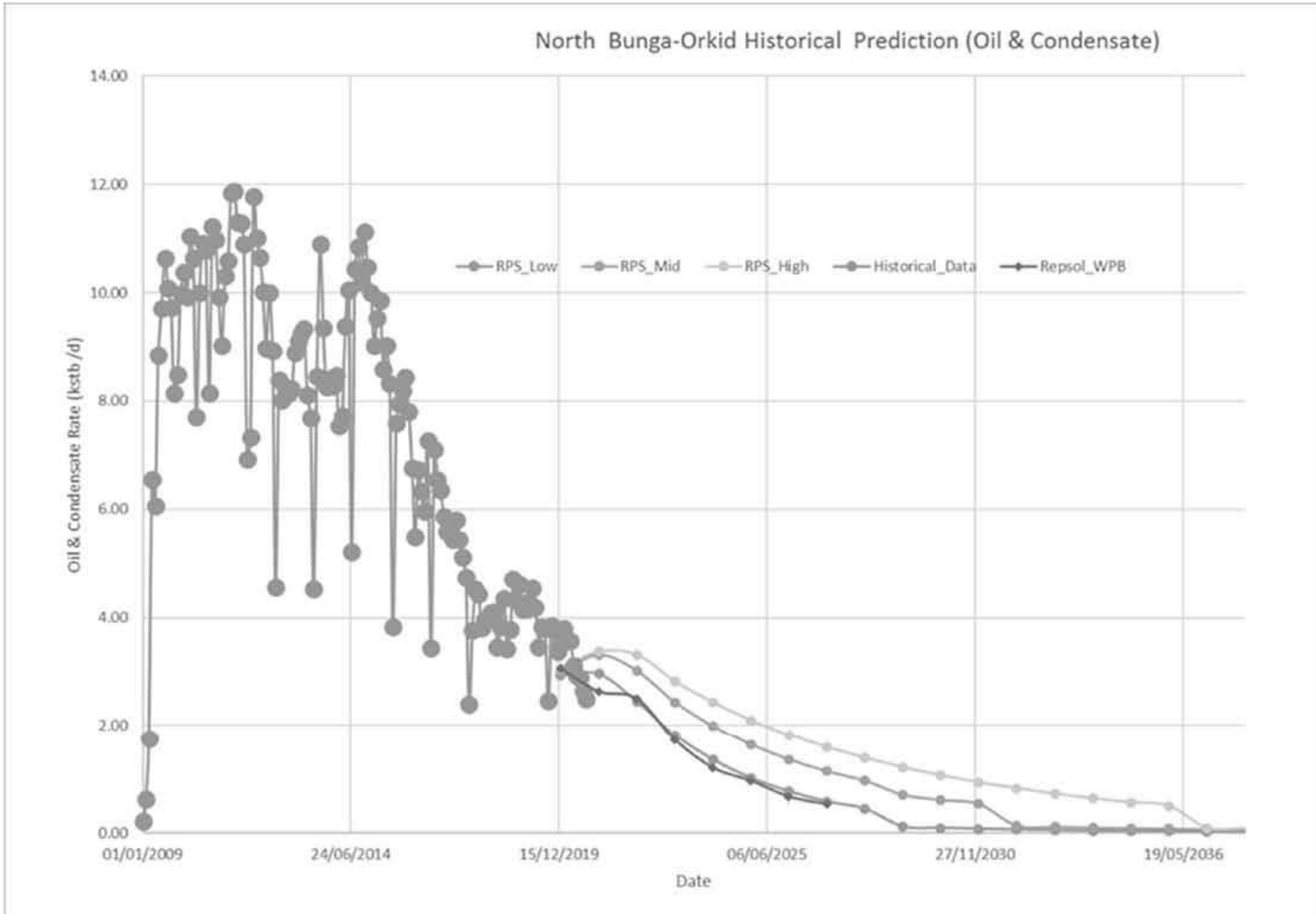


Figure F.4: North Bunga Orkid Oil & Condensate Forecast Plot

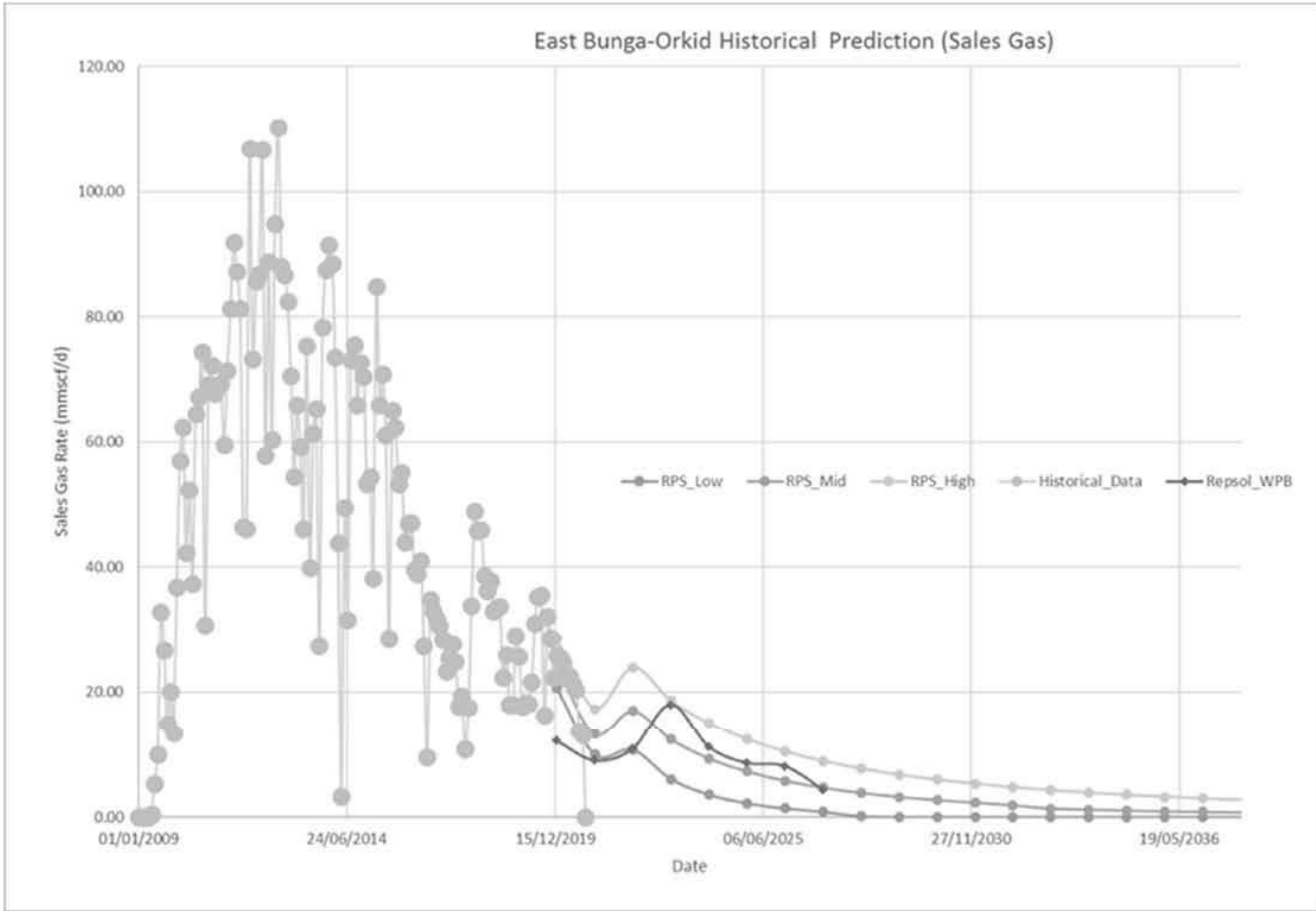


Figure F.5: East Bunga Orkid Sales Gas Forecast Plot

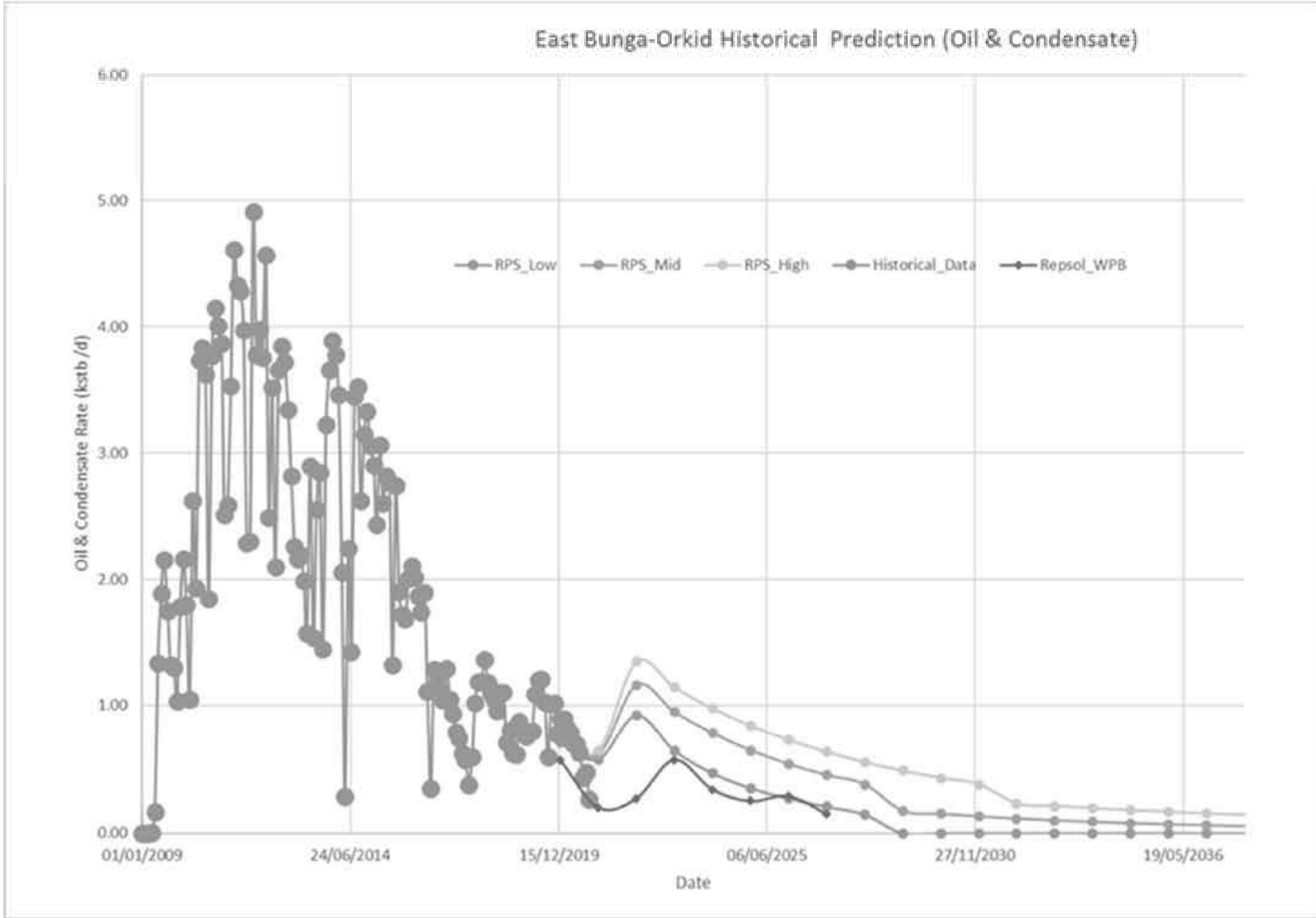


Figure F.6: East Bunga Orkid Oil & Condensate Forecast Plot

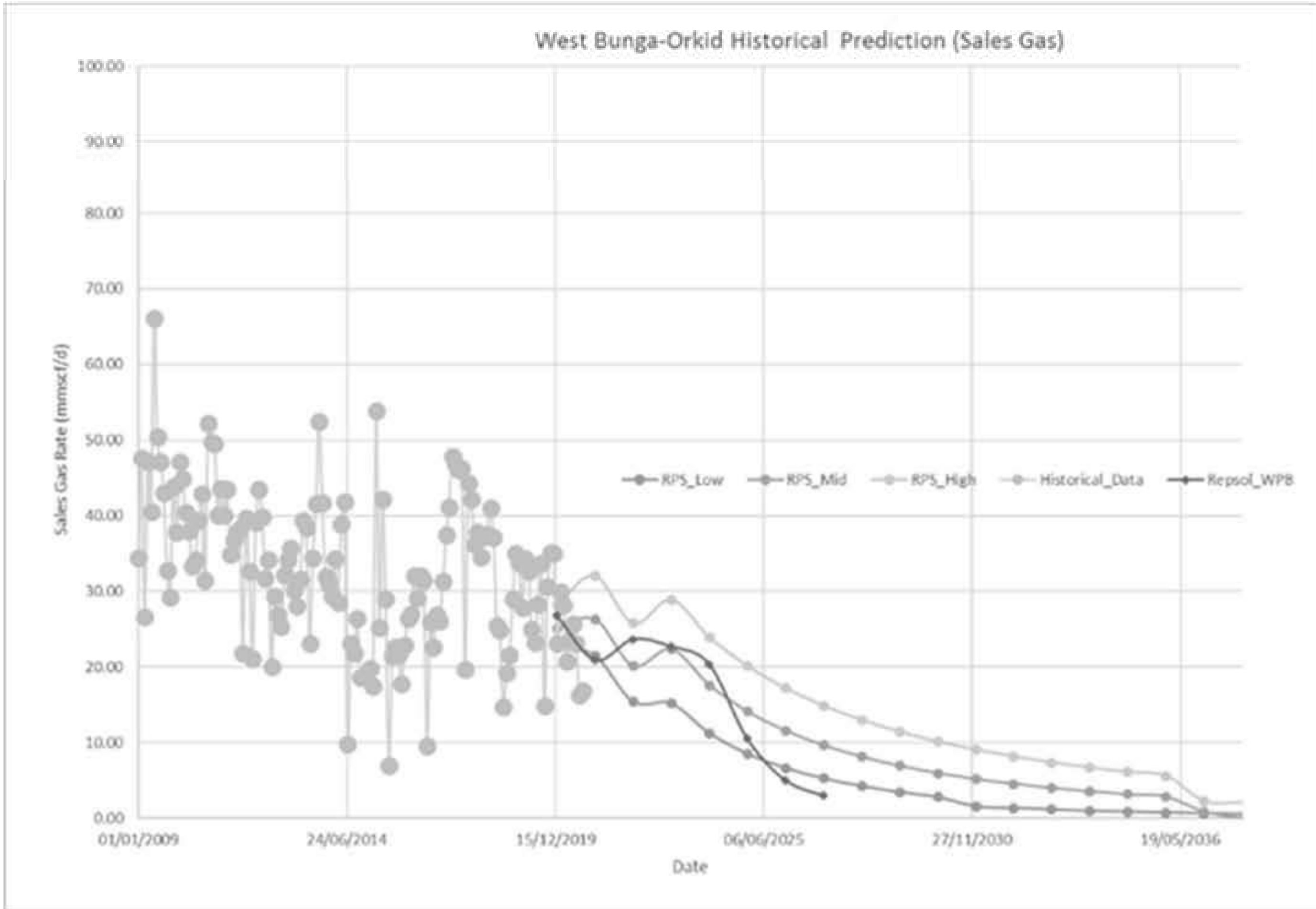


Figure F.7: West Bunga Orkid Sales Gas Forecast Plot

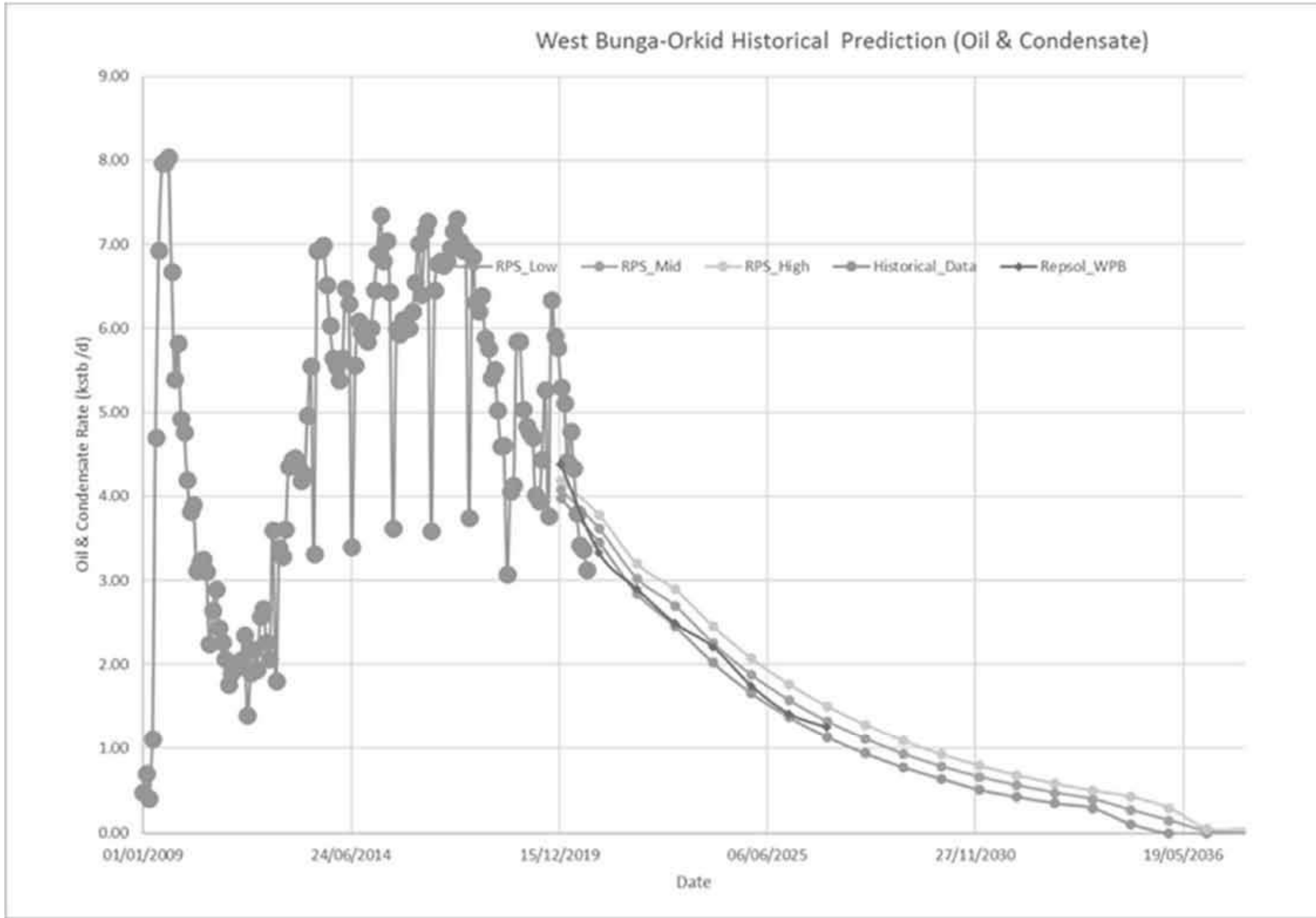


Figure F.8: **West Bunga Orkid Oil & Condensate Forecast Plot**

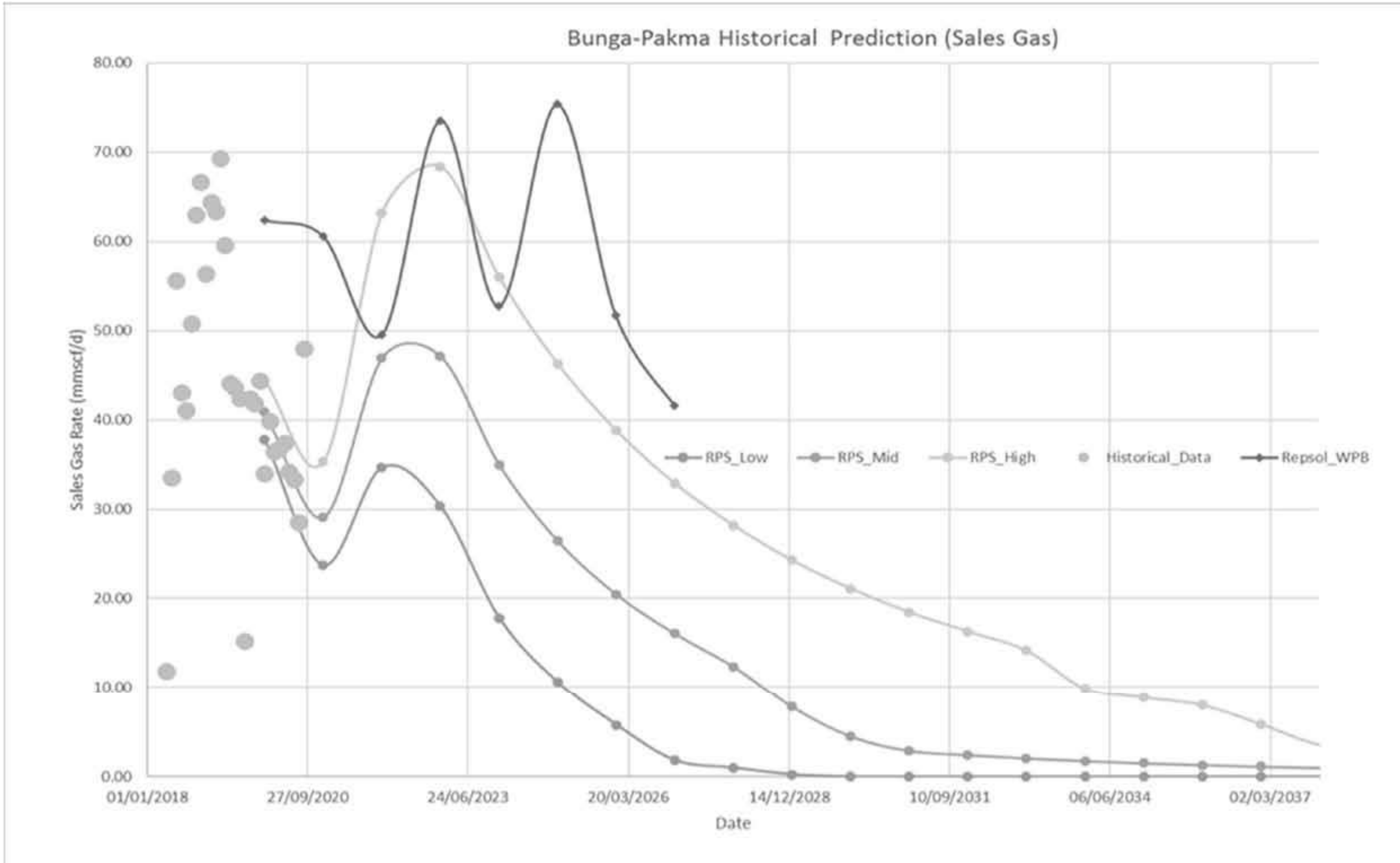


Figure F.9: Bunga Pakma Sales Gas Forecast Plot

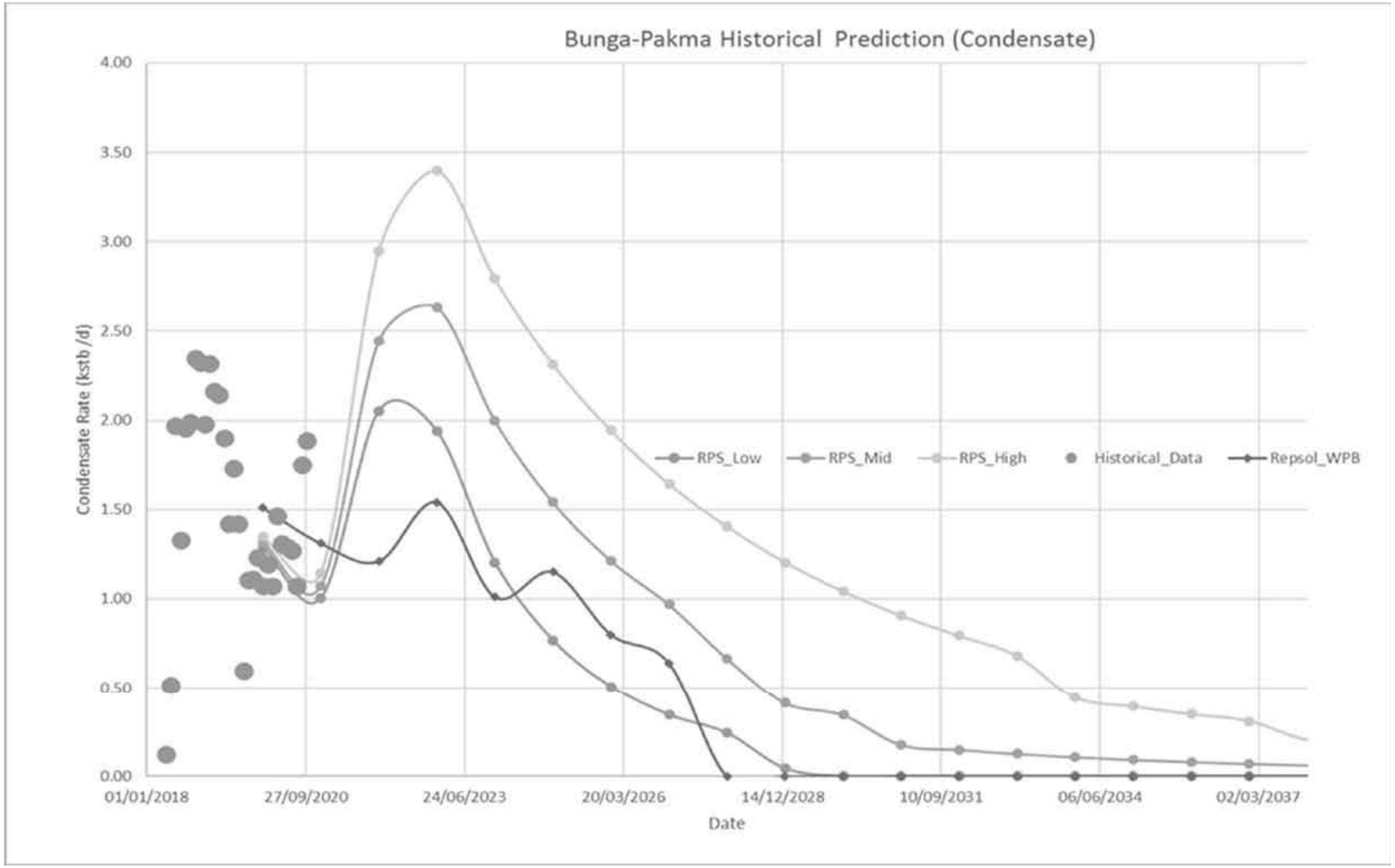


Figure F.10: Bunga Pakma Oil & Condensate Forecast Plot

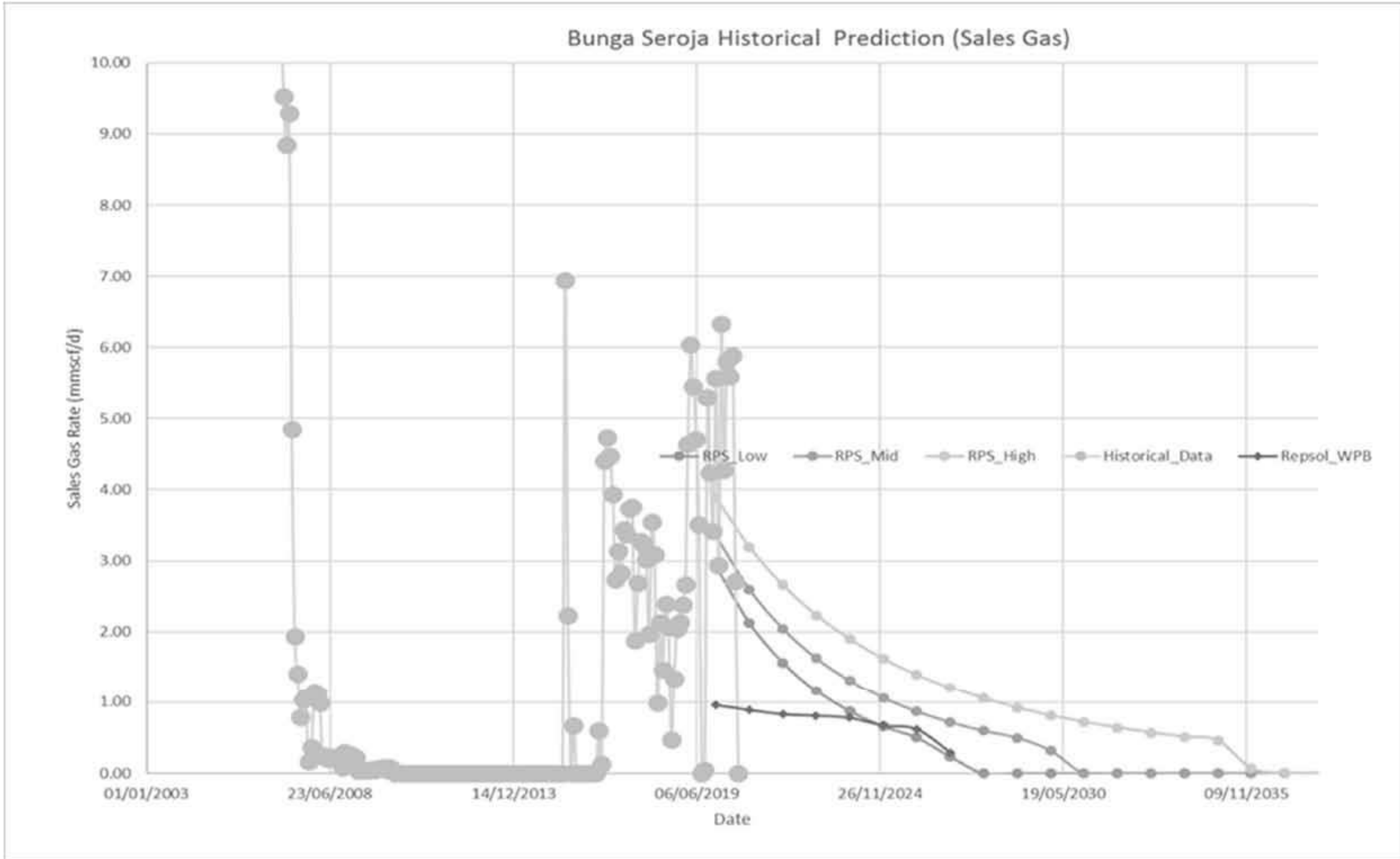


Figure F.11: Bunga Seroja Sales Gas Forecast Plot

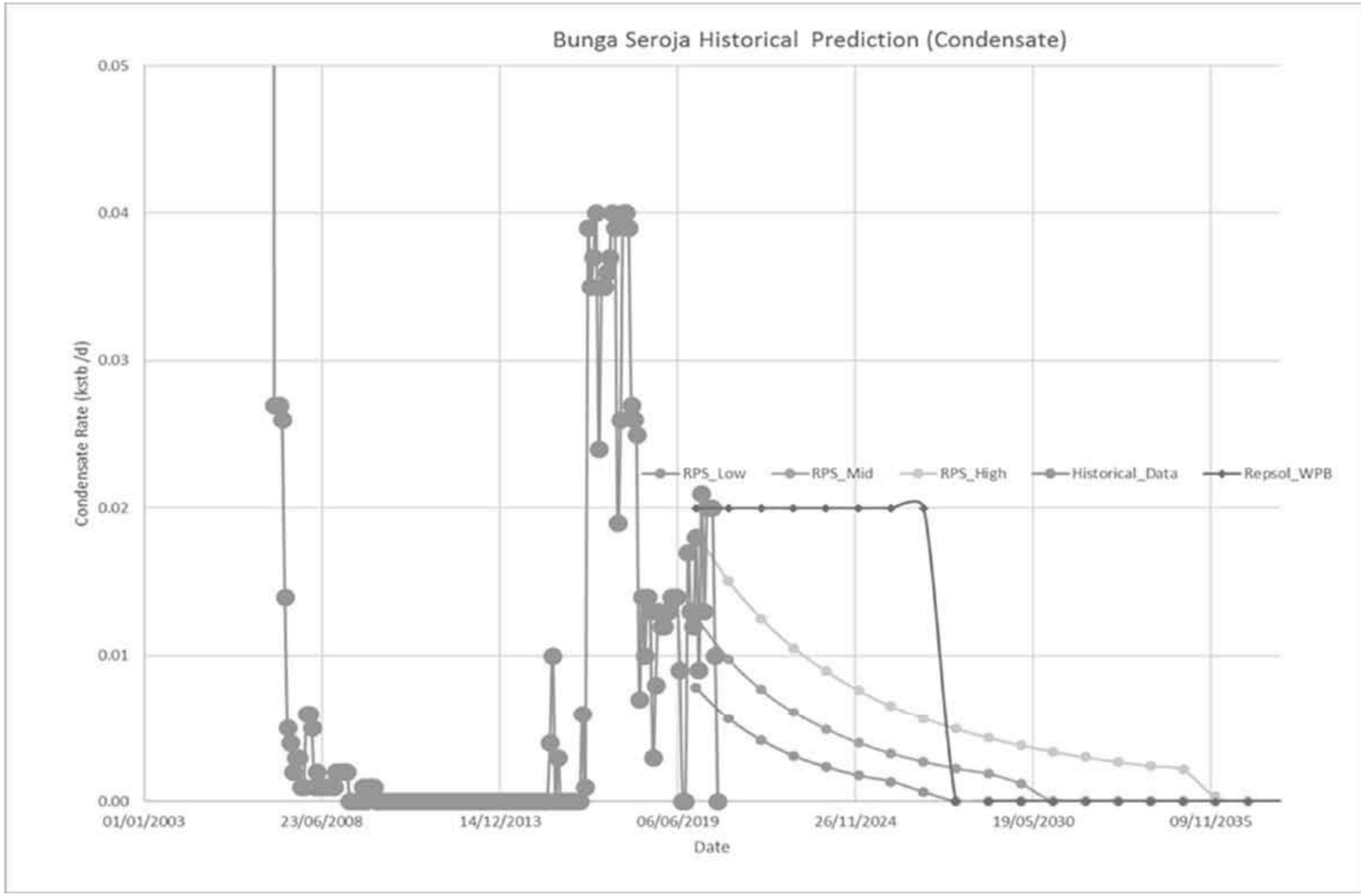


Figure F.12: Bunga Seroja Oil & Condensate Forecast Plot

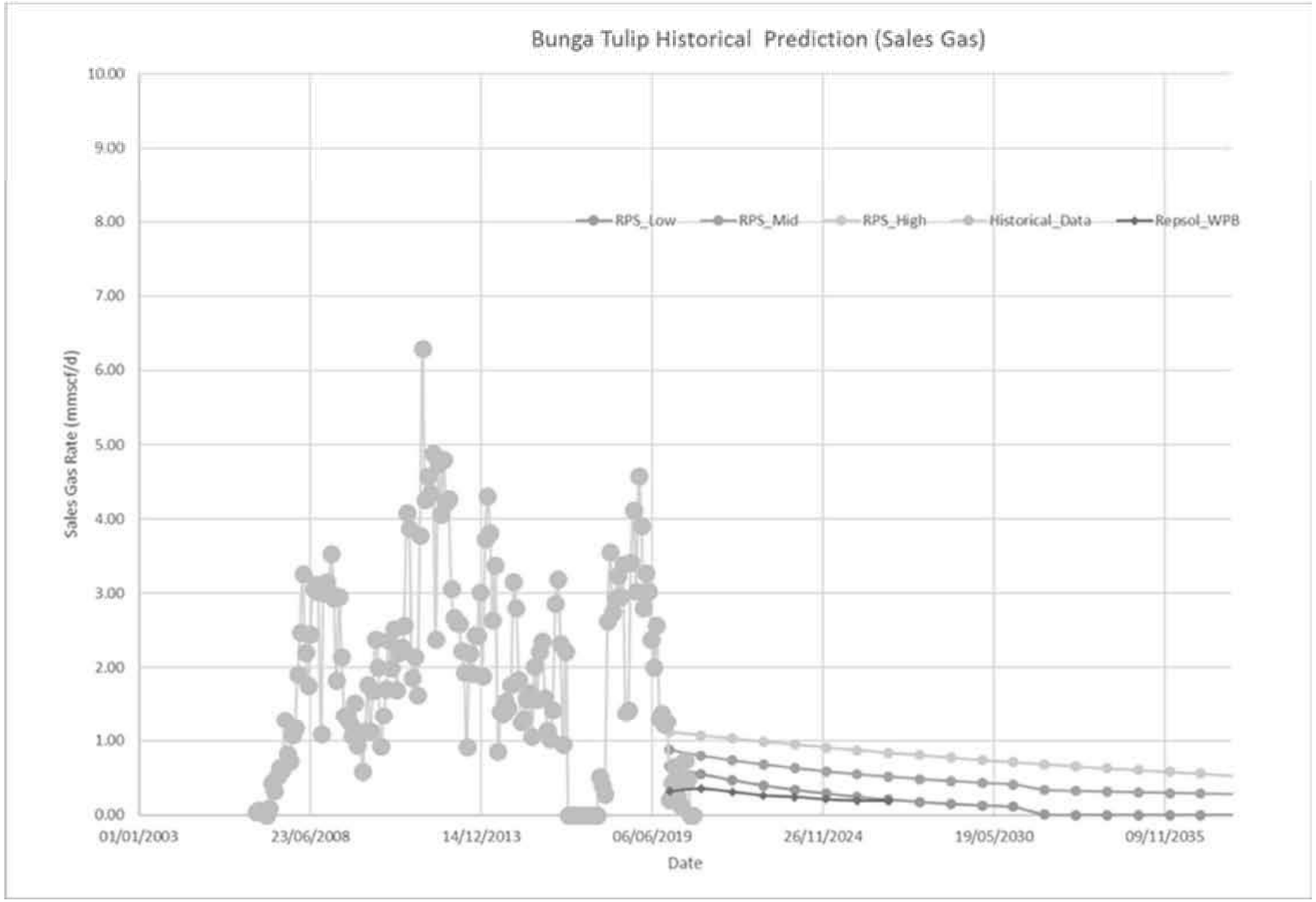


Figure F.13: Bunga Tulip Sales Gas Forecast Plot

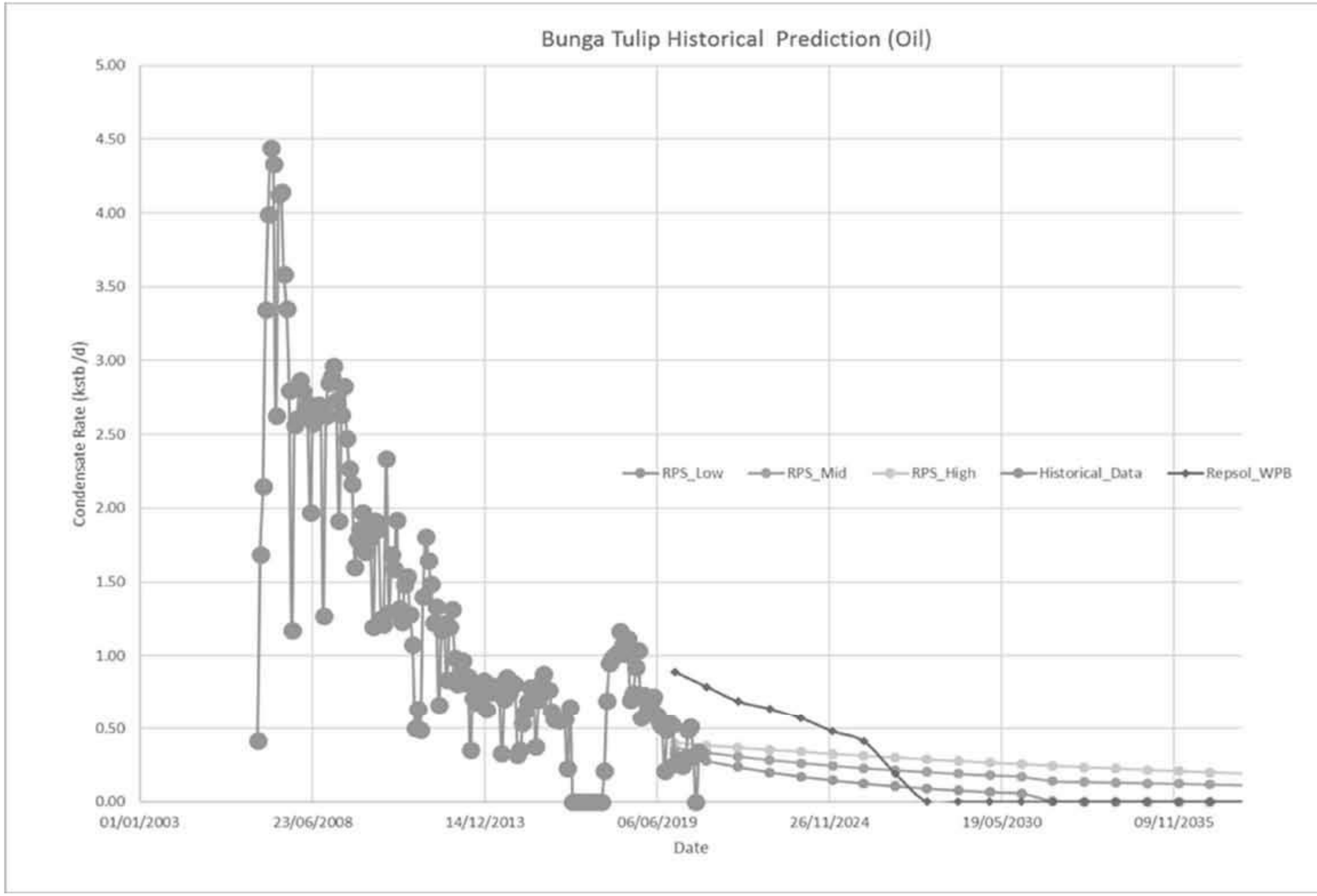


Figure F.14: Bunga Tulip Oil & Condensate Forecast Plot

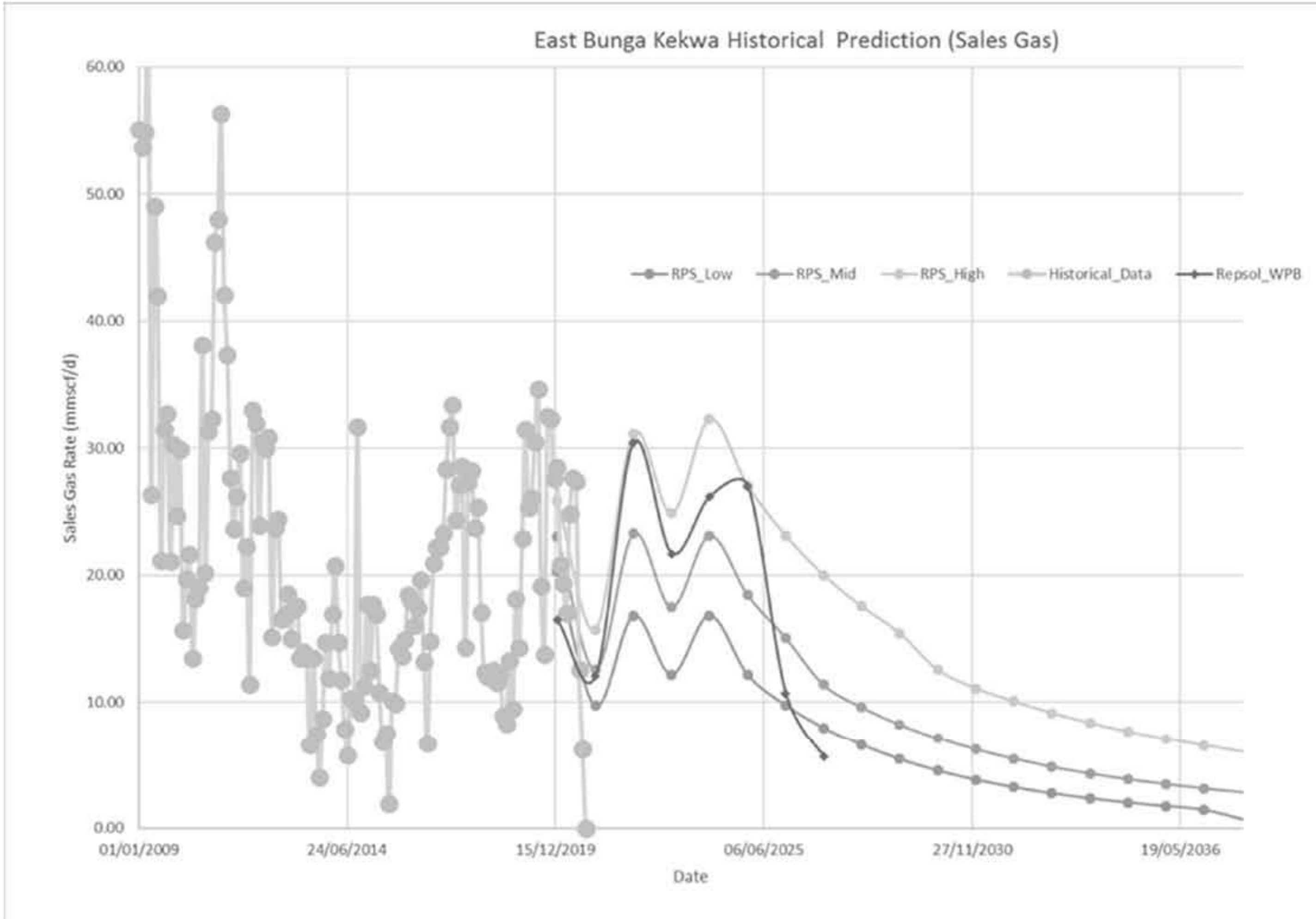


Figure F.15: East Bunga Kekwa Sales Gas Forecast Plot

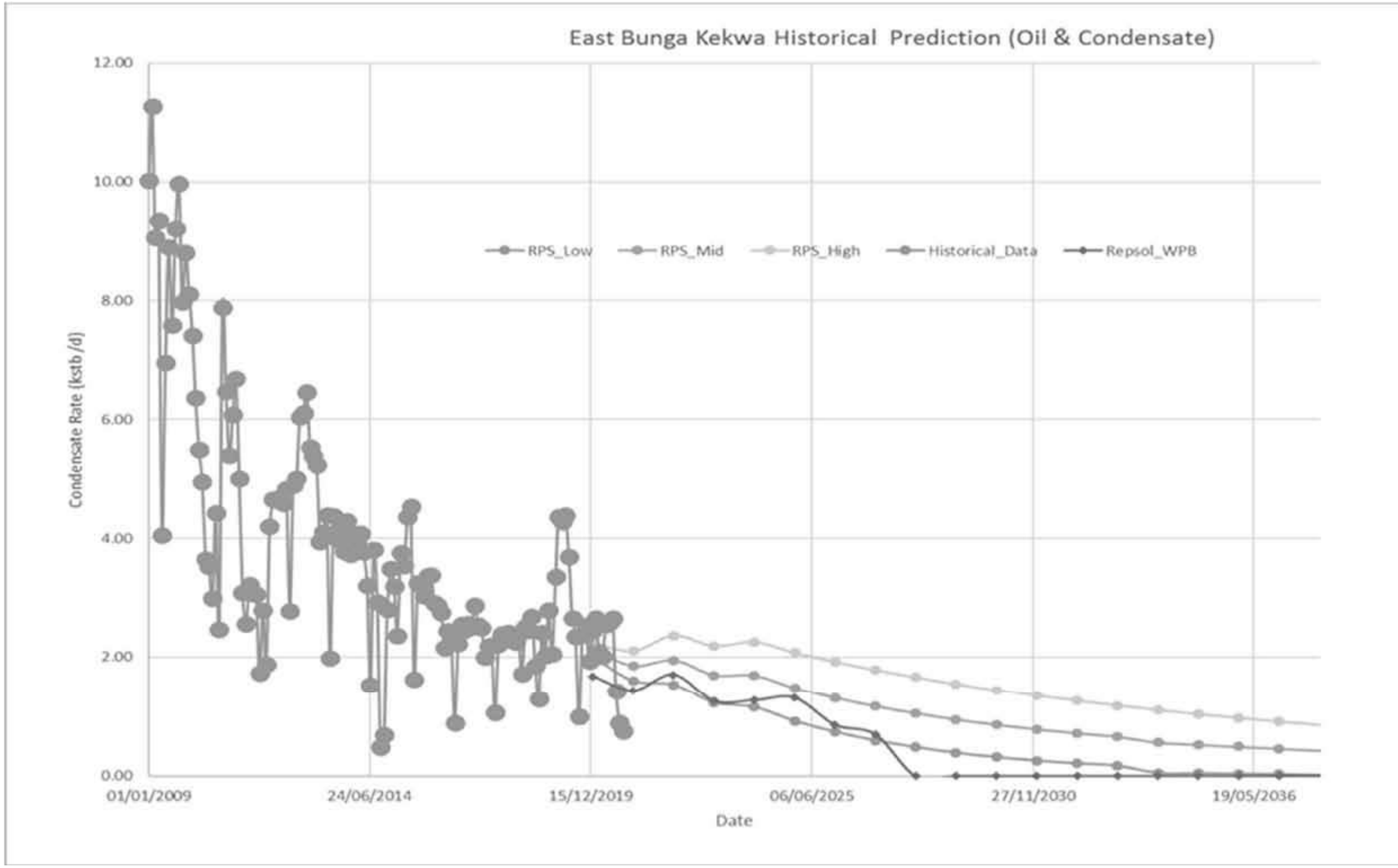


Figure F.16: East Bunga Kekwa Oil & Condensate Forecast Plot

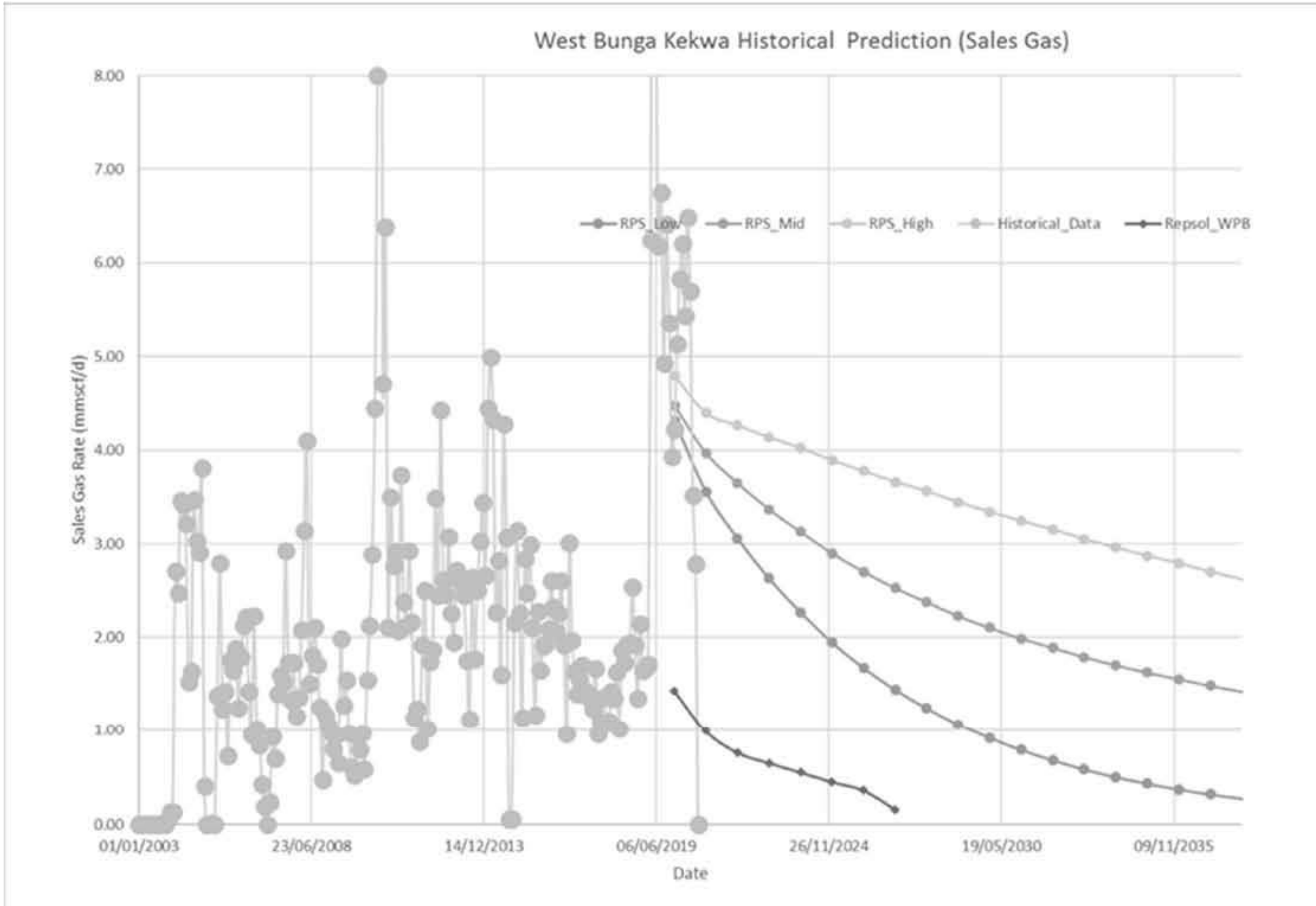


Figure F.17: West Bunga Kekwa Sales Gas Forecast Plot

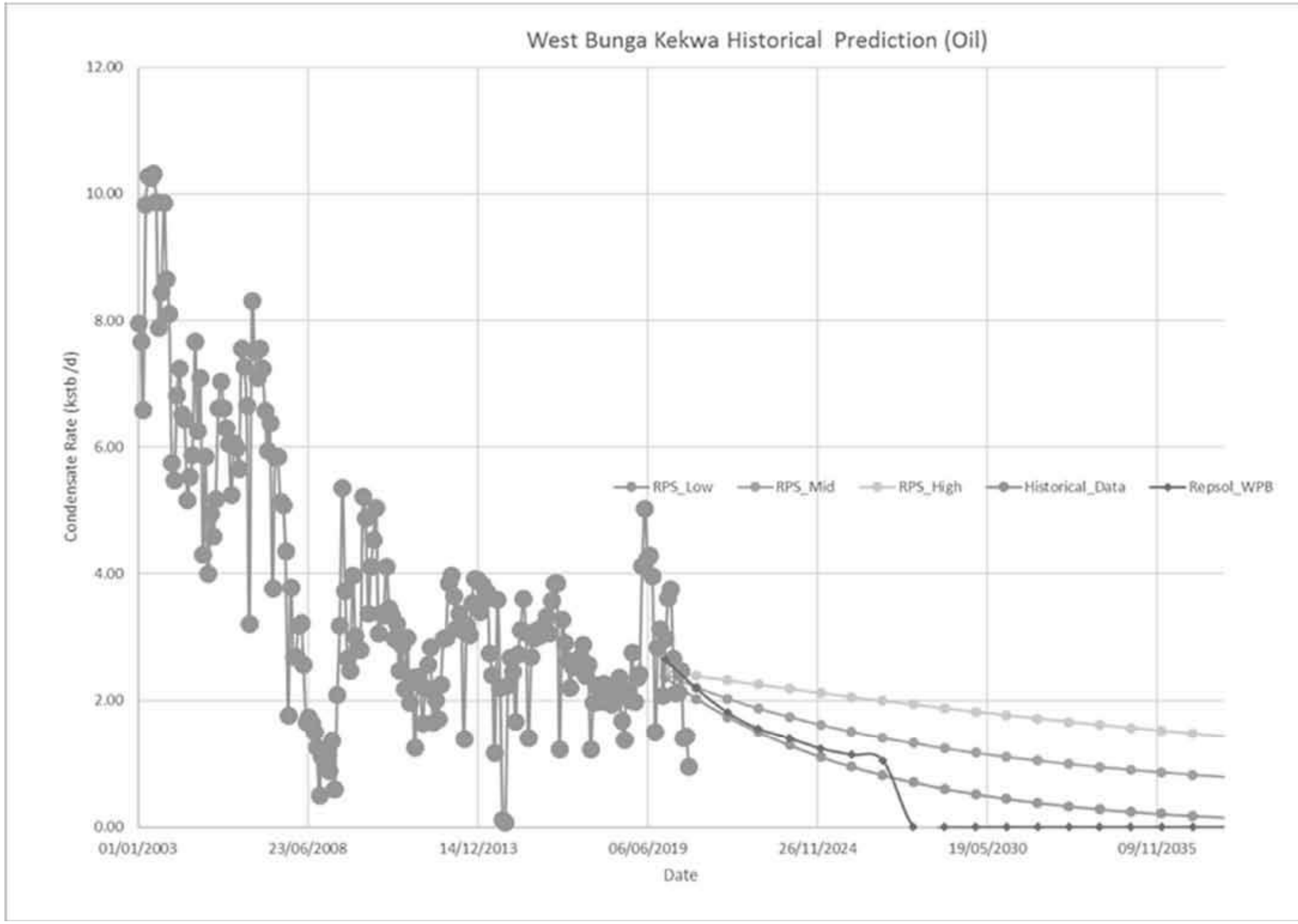


Figure F.18: West Bunga Kekwa Oil & Condensate Forecast Plot

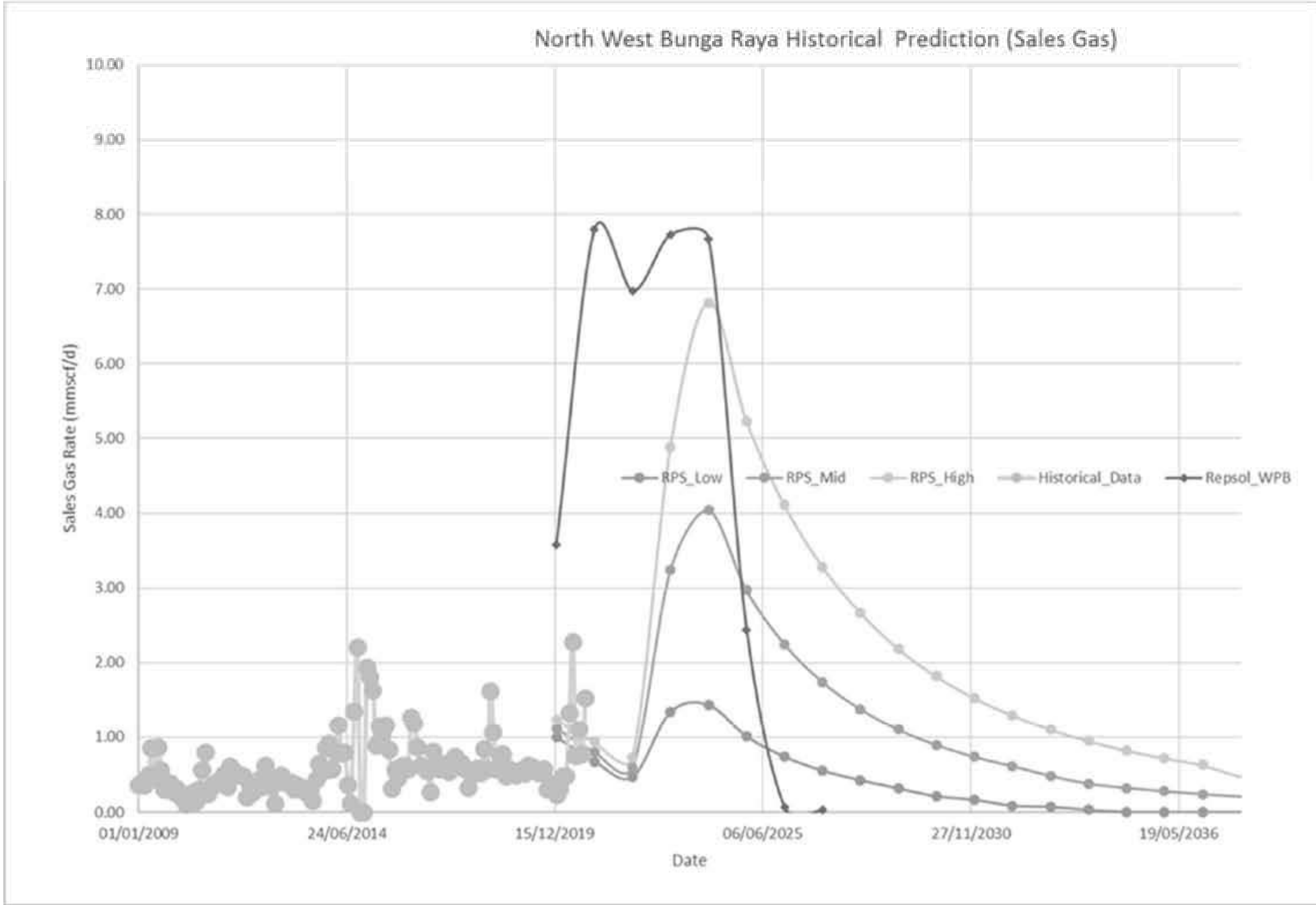


Figure F.19: Northwest Bunga Kekwa Sales Gas Forecast Plot

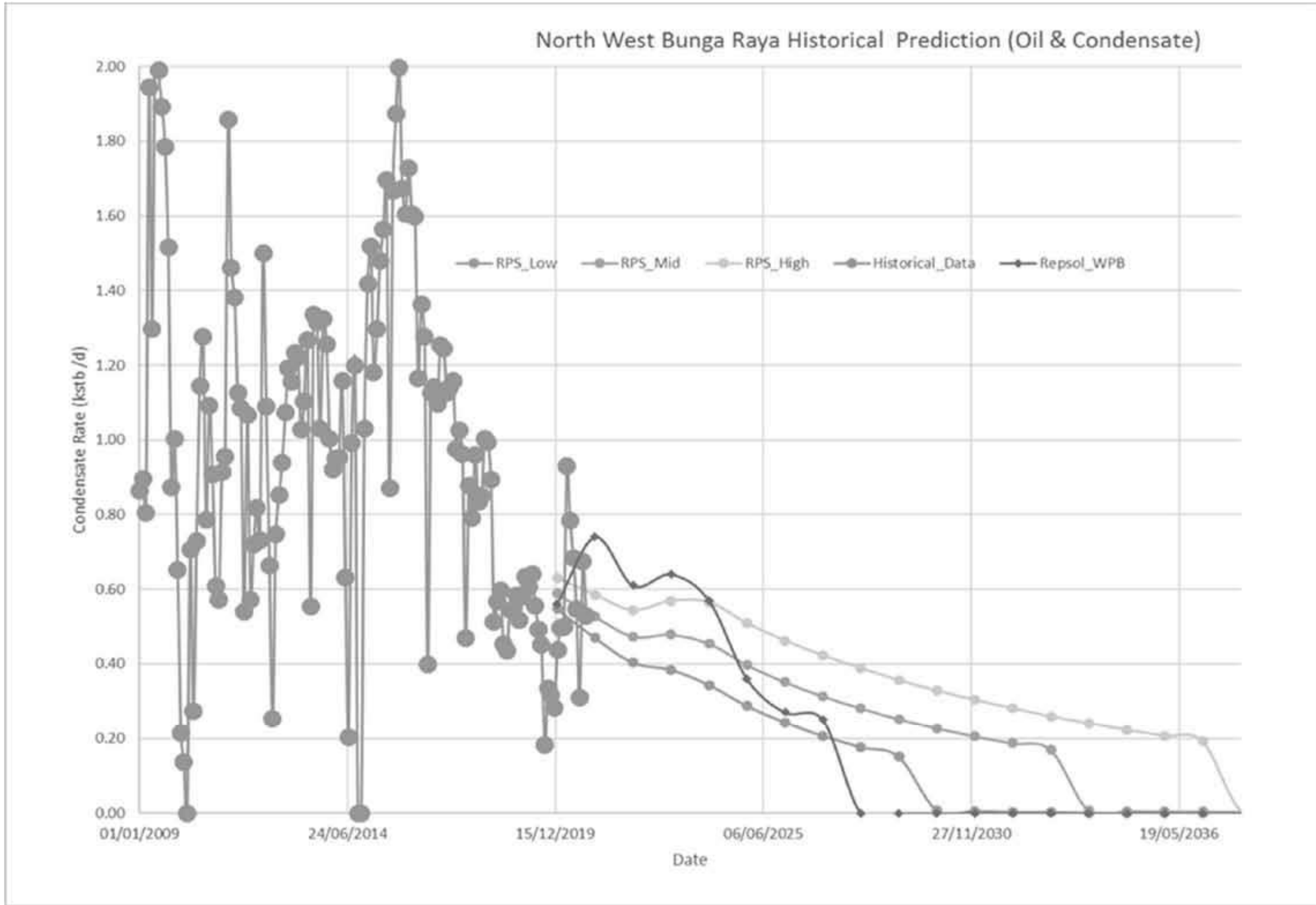


Figure F.20: Northwest Bunga Raya Oil & Condensate Forecast Plot

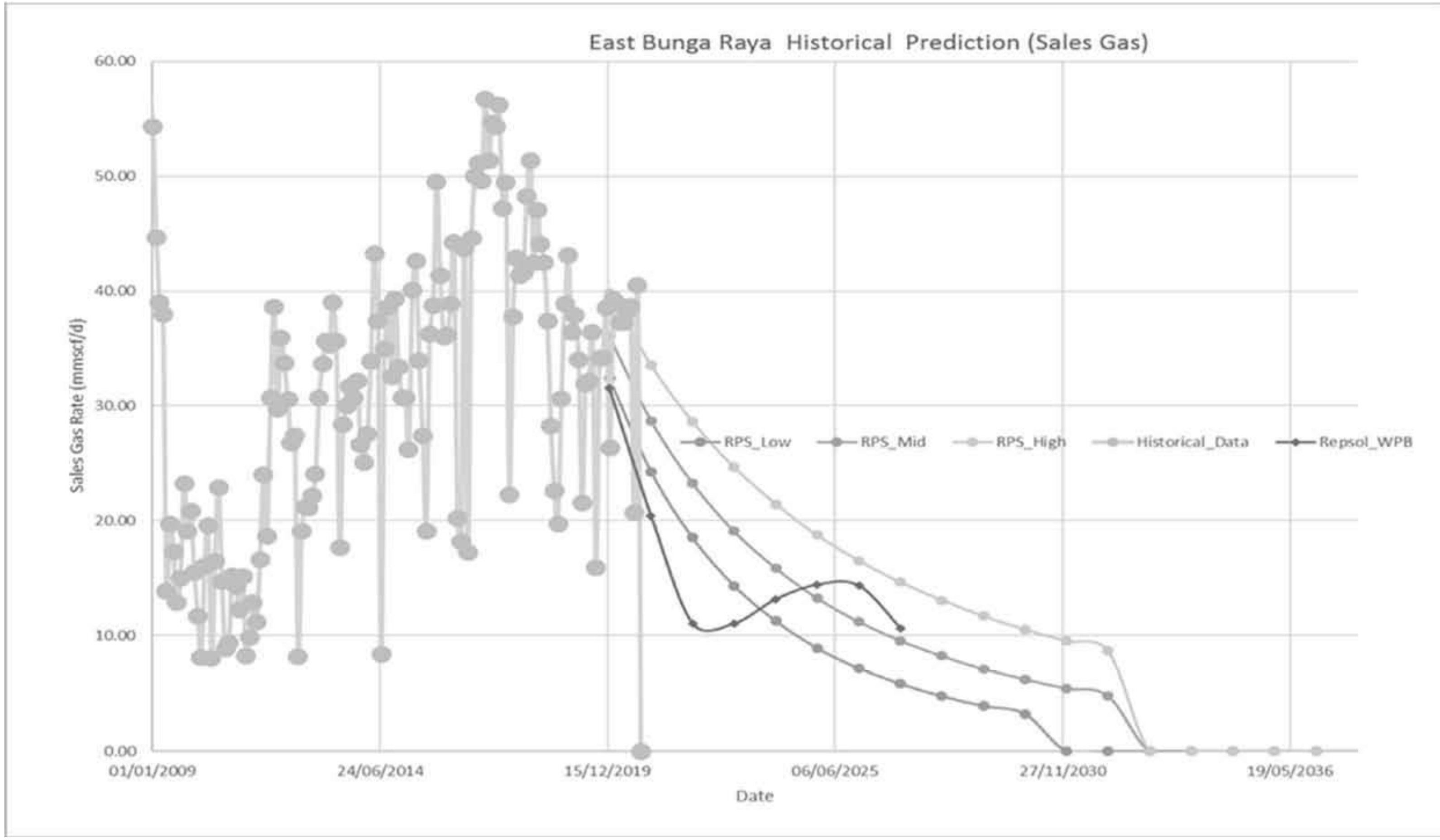


Figure F.21: East Bunga Raya Sales Gas Forecast Plot

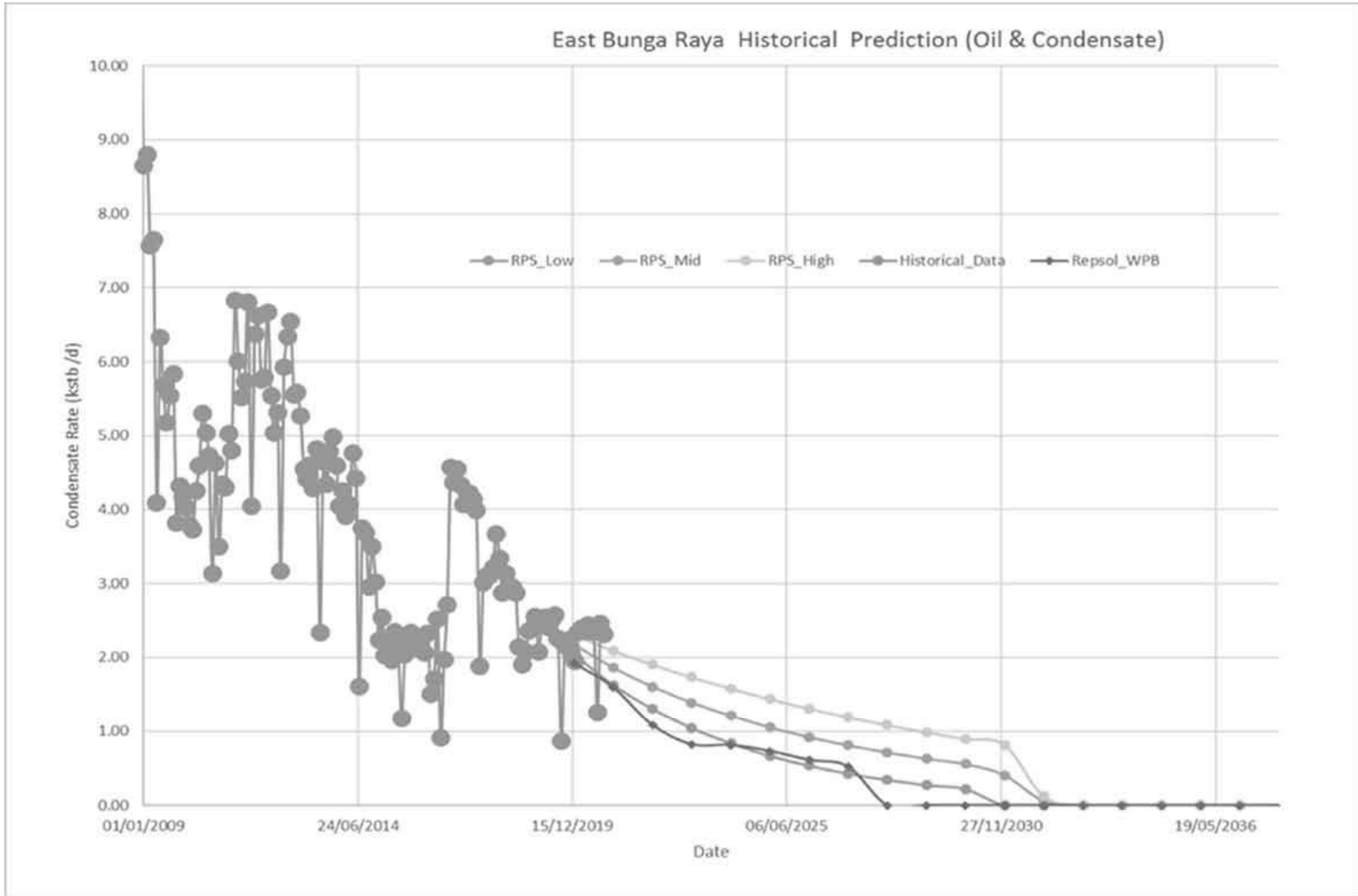


Figure F.22: East Bunga Raya Oil & Condensate Forecast Plot

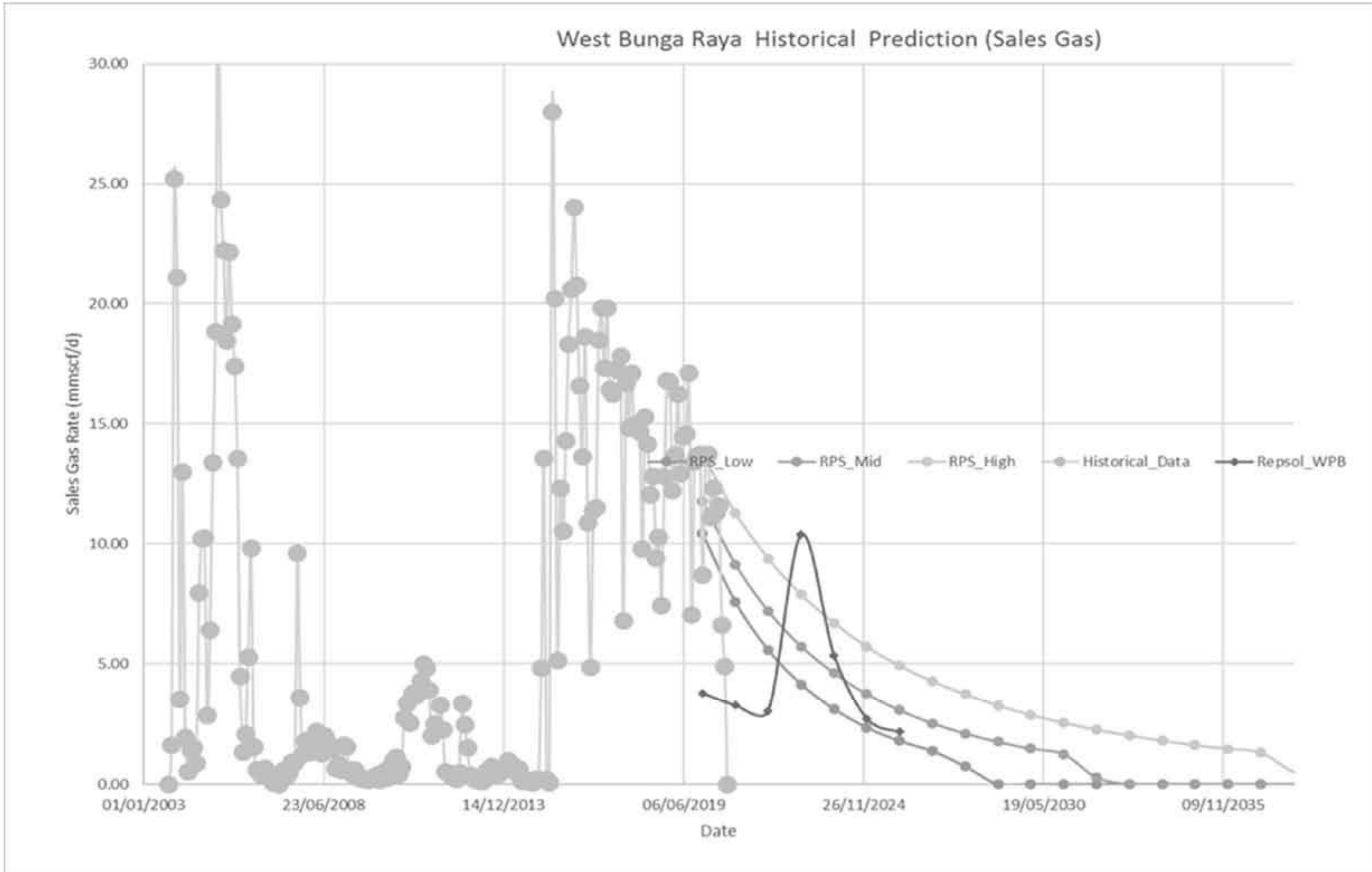


Figure F.23: West Bunga Raya Sales Gas Forecast Plot

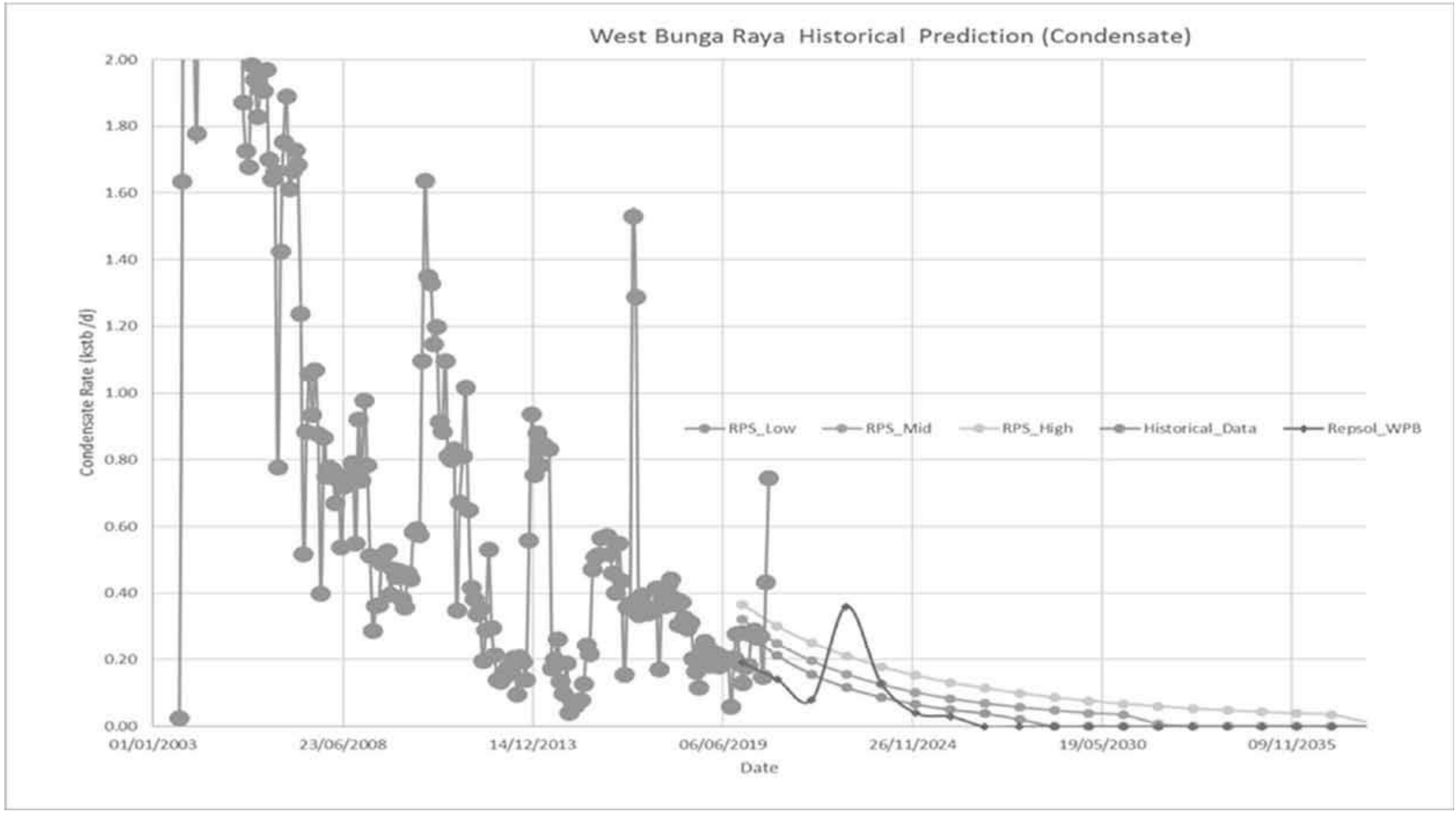


Figure F.24: West Bunga Raya Oil & Condensate Forecast Plot

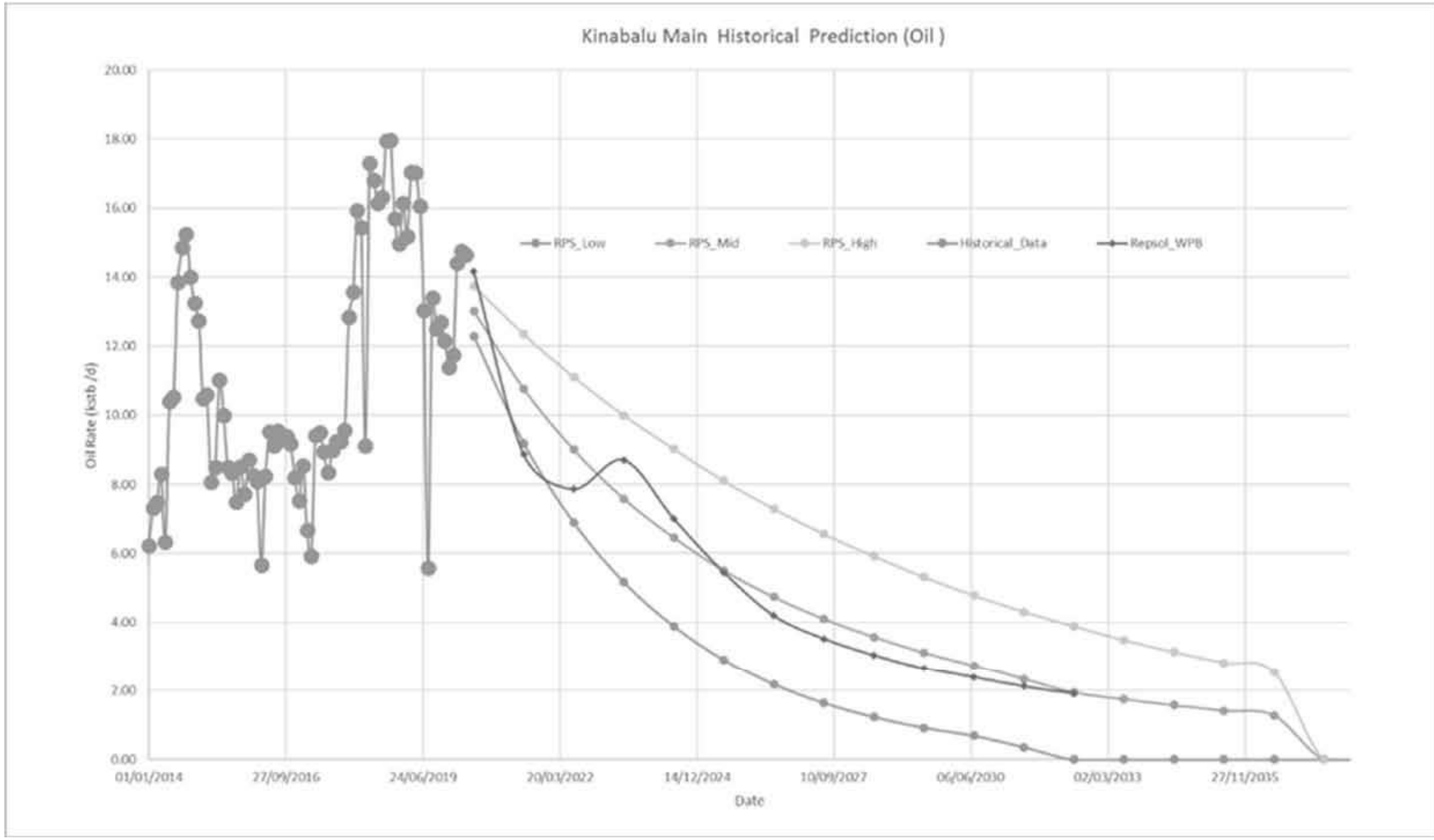


Figure F.25: Kinabalu Main Oil & Condensate Forecast Plot

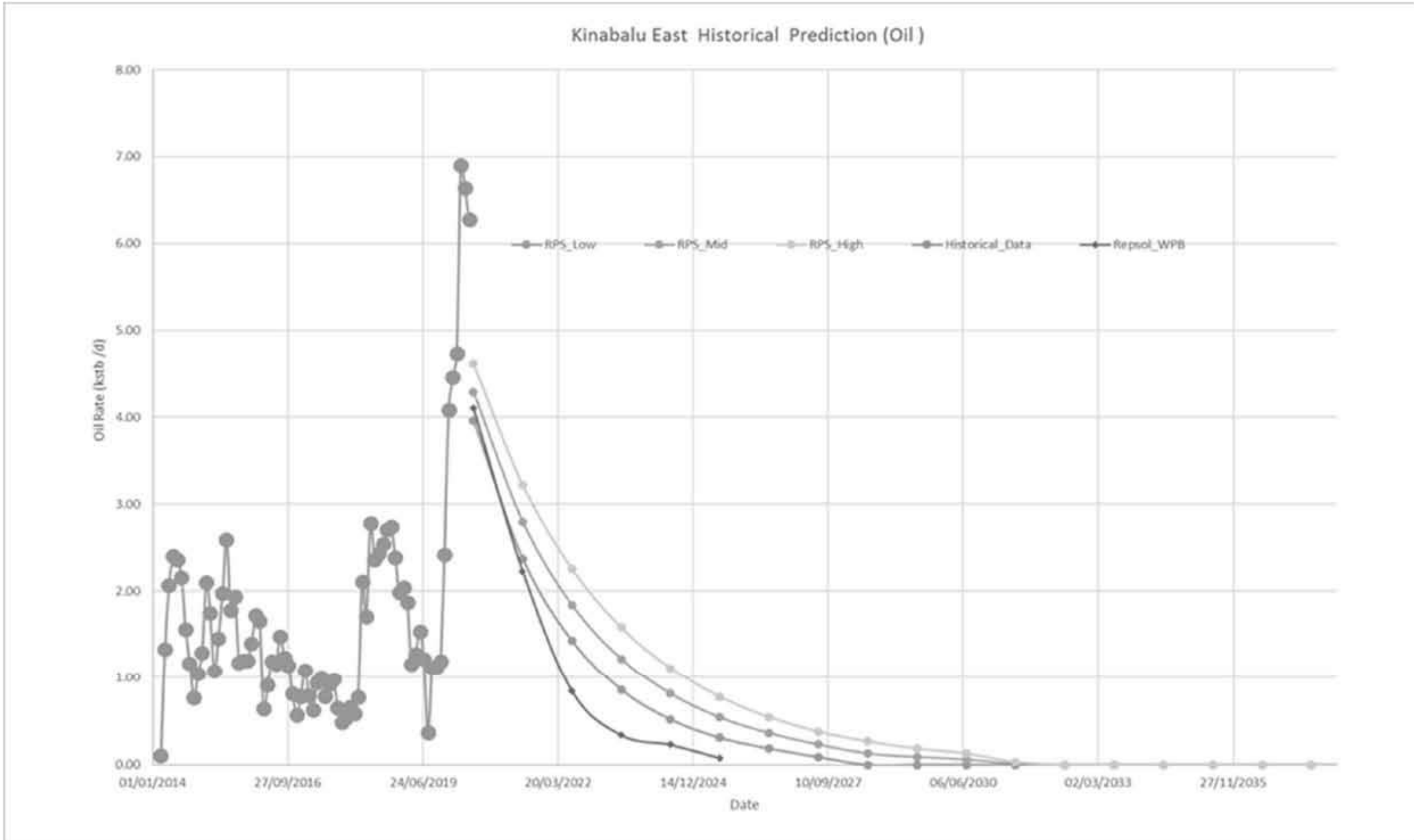


Figure F.26: Kinabalu East Oil & Condensate Forecast Plot

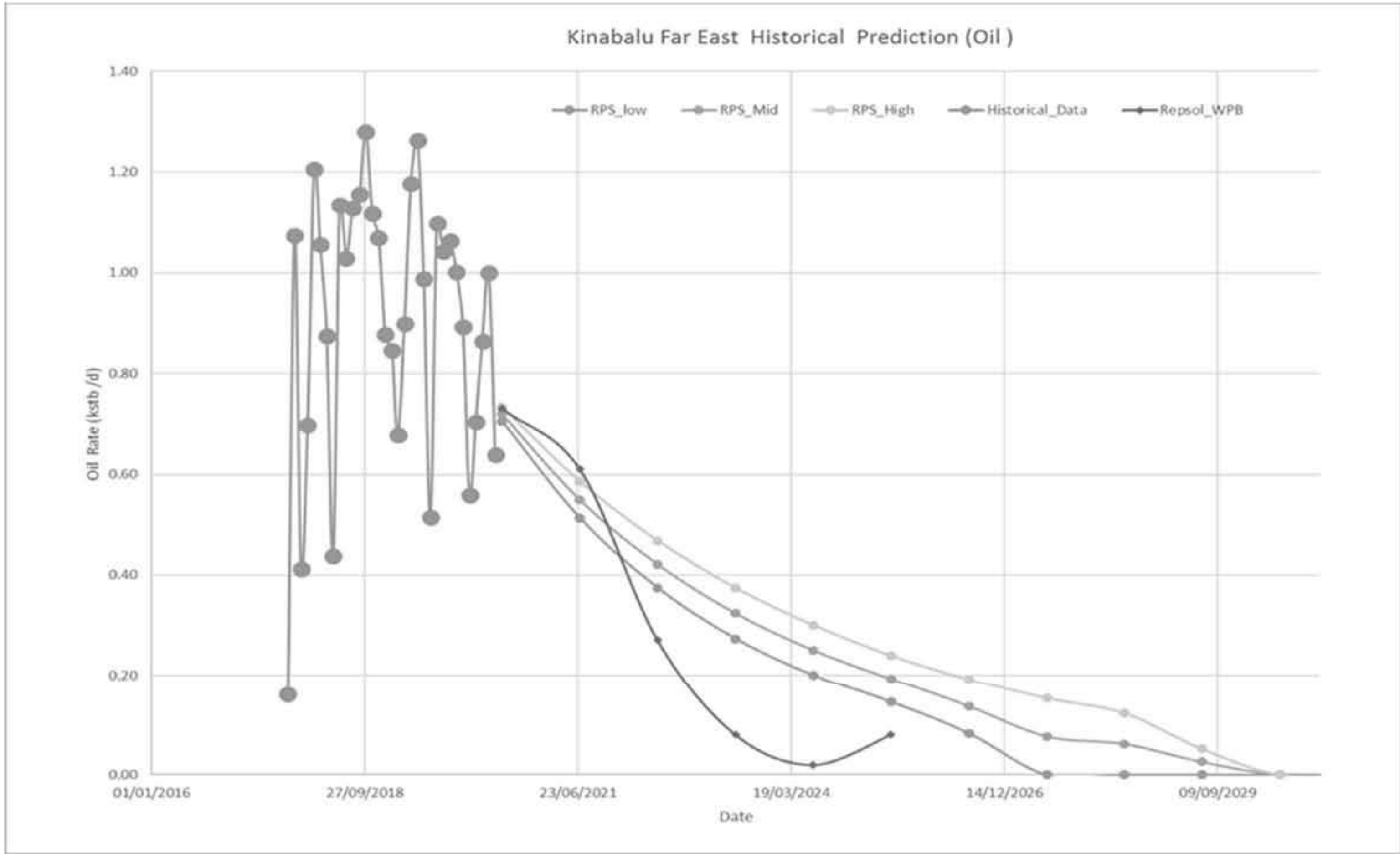


Figure F.27: Kinabalu Far East Oil & Condensate Forecast Plot

Appendix G
Cashflow Forecasts

1PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Gas Production	MMscfd		162	156	124	85	60
Gross Condensate Production	Bcpd		3,342	5,157	4,469	3,033	2,131
Gross Oil Production	Bopd		11,092	9,026	7,360	6,032	4,925
Gross Annual Gas Production	**Bscf**	**214.3**	**59**	**57**	**45**	**31**	**22**
Gross Annual Condensate Production	**MMstb**	**6.6**	**1**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**14.0**	**4**	**3**	**3**	**2**	**2**
Realized Gas Price	US$/MMBtu		4	4	4	3	4
Realized Condensate Price	US$/bbl		63	60	58	56	58
Realized Oil Price	US$/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	347	87	87	76	55	42
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	108	35	29	20	13	10
Net Entitlement to Repsol			22%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		35	35	29	20	14
Net Condensate Production to Repsol	Bcpd		725	1,156	1,040	709	496
Net Oil Production to Repsol	Bopd		2,407	2,023	1,713	1,410	1,146
Net Annual Gas Production to Repsol	**Bscf**	**48.5**	**13**	**13**	**11**	**7**	**5**
Net Annual Condensate Production to Repsol	**MMstb**	**1.5**	**0**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**3.2**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	455	122	117	96	68	53
Net Opex to Repsol	MMUS$	(341)	(65)	(72)	(71)	(67)	(66)
Net Capex to Repsol	MMUS$	(12)	(2)	(3)	(2)	(2)	(2)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(19)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(2)	(1)	(1)	(0)	(0)	(0)
Overhead Payment from Partner	MMUS$	14	3	3	3	3	3
Net Export Duty-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(7)	0	(6)	(1)	0	0
One-time extension bonus payment	MMUS$	2	0	1	1	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**46**	**51**	**26**	**13**	**(12)**	**(33)**
NPV @ 10% Net to Repsol	**MMUS$**	**54**					

1PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026
Gross Oil Production Rate	Bopd		11,108	7,994	5,792	4,234	3,092	2,252
Gross Annual Oil Production	**MMstb**	**12.6**	**4**	**3**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61
Cost Recovery to Repsol	MMUS$	177	29	43	37	27	23	18
Repsol's Share of Unused & Profit Oil	MMUS$	119	58	27	14	10	6	4
Net Entitlement to Repsol			34%	40%	43%	43%	45%	45%
Net Oil Production to Repsol	Bopd	5	3,761	3,186	2,470	1,818	1,391	1,013
Net Annual Oil Production to repsol	**MMstb**	**5.0**	**1**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	296	86	69	52	37	29	22
Net Opex to Repsol	MMUS$	(158)	(25)	(32)	(26)	(25)	(25)	(24)
Net Capex to Repsol	MMUS$	(26)	(3)	(9)	(11)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(16)
Net Supplementary Payment	MMUS$	(26)	(15)	(6)	(3)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(1)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(4)	(4)	0	0	0	0	0
Net Export Duty	MMUS$	(12)	(6)	(3)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	2	0	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**53**	**33**	**19**	**11**	**8**	**2**	**(20)**
NPV @ 10% Net to Repsol	**MMUS$**	**54**						

1PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Oil & Condensate Production Rate	Bopd		383	394	315	253	203
Gross Annual Oil & Condensate Production	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	9	2	2	2	1	1
Repsol's Share of Profit Oil	MMUS$	5	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	163	168	134	108	86
Net Annual Oil Production to repsol	MMstb	**0.2**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	14	4	4	3	2	2
Net Opex to Repsol	MMUS$	(12)	(3)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(5)
Net Export Duty	MMUS$	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**(5)**	**1**	**1**	**(0)**	**(1)**	**(5)**
NPV @ 10% Net to Repsol	**MMUS$**	**(3)**					

1PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

1P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Gas Production	MMscfd		162	159	128	87	61
Gross Condensate Production	Bcpd		3,342	5,320	4,649	3,152	2,245
Gross Oil Production	Bopd		11,090	10,256	10,484	8,771	7,762
Gross Annual Gas Production	**Bscf**	**217.3**	**59**	**58**	**47**	**32**	**22**
Gross Annual Condensate Production	**MMstb**	**6.8**	**1**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**17.7**	**4**	**4**	**4**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4
Realized Condensate Price	US$/bbl		63	60	58	56	58
Realized Oil Price	US$/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	387	90	94	85	65	54
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	119	34	31	25	16	13
Net Entitlement to Repsol			22%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		36	36	29	20	14
Net Condensate Production to Repsol	Bcpd		738	1,196	1,053	729	515
Net Oil Production to Repsol	Bopd		2,448	2,307	2,374	2,027	1,781
Net Annual Gas Production to Repsol	**Bscf**	**49.0**	**13**	**13**	**11**	**7**	**5**
Net Annual Condensate Production to Repsol	**MMstb**	**1.5**	**0**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**4.0**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	506	124	125	110	81	67
Net Opex to Repsol	MMUS$	(346)	(65)	(72)	(73)	(69)	(67)
Net Capex to Repsol	MMUS$	(72)	(17)	(48)	(2)	(2)	(2)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(20)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(3)	(1)	(1)	(1)	(0)	(0)
Overhead Payment from Partner	MMUS$	17	3	5	3	3	3
Net Export Duty-Repsol	MMUS$	(6)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	0	0	0	0	0	0
One-time extension bonus payment	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**38**	**38**	**(4)**	**26**	**(1)**	**(21)**
NPV @ 10% Net to Repsol	**MMUS$**	**41**					

1P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil Production Rate	Bopd		11,108	9,604	8,186	5,810	4,172	3,008	2,130
Gross Annual Oil Production	**MMstb**	**16.1**	**4**	**4**	**3**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	231	29	69	38	27	27	24	18
Repsol's Share of Unused & Profit Oil	MMUS$	148	58	22	29	19	11	6	4
Net Entitlement to Repsol			34%	44%	39%	39%	43%	45%	45%
Net Oil Production to Repsol	Bopd	6	3,761	4,193	3,167	2,280	1,774	1,354	958
Net Annual Oil Production to repsol	**MMstb**	**6.4**	**1**	**2**	**1**	**1**	**1**	**0**	**0**
Net Revenue to Repsol	MMUS$	380	86	91	67	46	37	30	22
Net Opex to Repsol	MMUS$	(183)	(25)	(32)	(27)	(26)	(25)	(25)	(23)
Net Capex to Repsol	MMUS$	(53)	(3)	(35)	(11)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	(14)
Net Supplementary Payment	MMUS$	(31)	(15)	(5)	(5)	(3)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(2)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(4)	(4)	0	0	0	0	0	0
Net Export Duty	MMUS$	(15)	(6)	(2)	(3)	(2)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	2	0	1	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**77**	**33**	**16**	**21**	**15**	**8**	**1**	**(18)**
NPV @ 10% Net to Repsol	**MMUS$**	**73**							

1P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025
Gross Oil & Condensate Production Rate	Bopd		383	394	315	253	203
Gross Annual Oil & Condensate Production	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58
Cost Recovery to Repsol	MMUS$	9	2	2	2	1	1
Repsol's Share of Profit Oil	MMUS$	5	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	163	168	134	108	86
Net Annual Oil Production to repsol	MMstb	**0.2**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	14	4	4	3	2	2
Net Opex to Repsol	MMUS$	(12)	(3)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(5)
Net Export Duty	MMUS$	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**(5)**	**1**	**1**	**(0)**	**(1)**	**(5)**
NPV @ 10% Net to Repsol	**MMUS$**	**(3)**					

1P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		198	209	184	143	113	90	73
Gross Condensate Production	Bcpd		4,091	6,447	6,261	4,922	3,934	3,201	2,598
Gross Oil Production	Bopd		12,067	10,429	9,059	7,932	6,941	6,121	5,383
Gross Annual Gas Production	**Bscf**	**368.5**	**72**	**76**	**67**	**52**	**41**	**33**	**27**
Gross Annual Condensate Production	**MMstb**	**11.5**	**1**	**2**	**2**	**2**	**1**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**21.1**	**4**	**4**	**3**	**3**	**3**	**2**	**2**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	532	80	93	91	81	71	63	54
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	194	49	44	34	21	17	15	13
Net Entitlement to Repsol			20%	21%	22%	23%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		39	44	41	33	26	21	17
Net Condensate Production to Repsol	Bcpd		805	1,349	1,384	1,148	924	750	607
Net Oil Production to Repsol	Bopd		2,373	2,183	2,002	1,850	1,630	1,435	1,258
Net Annual Gas Production to Repsol	**Bscf**	**80.8**	**14**	**16**	**15**	**12**	**10**	**8**	**6**
Net Annual Condensate Production to Repsol	**MMstb**	**2.5**	**0**	**0**	**1**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**4.6**	**1**	**1**	**1**	**1**	**1**	**1**	**0**
Net Revenue to Repsol	MMUS$	726	129	136	124	103	88	78	68
Net Opex to Repsol	MMUS$	(512)	(69)	(77)	(77)	(73)	(72)	(73)	(72)
Net Capex to Repsol	MMUS$	(17)	(2)	(3)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(4)	(1)	(1)	(1)	(1)	(0)	(0)	(0)
Overhead Payment from Partner	MMUS$	19	2	2	2	3	3	3	3
Net Export Duty-Repsol	MMUS$	(8)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(30)	(6)	(13)	(9)	(2)	0	0	0
One-time extension bonus payment	MMUS$	4	1	1	1	1	0	0	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**120**	**49**	**33**	**27**	**14**	**7**	**(1)**	**(10)**
NPV @ 10% Net to Repsol	**MMUS$**	**111**							

2PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		12,983	10,360	8,394	6,917	5,737	4,816	4,055	3,469	2,976	2,577	2,161	1,787
Gross Annual Oil Production	**MMstb**	**24.2**	**5**	**4**	**3**	**3**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	342	29	44	38	28	27	29	27	27	28	25	22	18
Repsol's Share of Unused & Profit Oil	MMUS$	245	70	41	30	25	20	15	12	9	7	6	5	5
Net Entitlement to Repsol			33%	37%	39%	38%	39%	41%	42%	43%	45%	45%	45%	45%
Net Oil Production to Repsol	Bopd	9	4,314	3,885	3,236	2,609	2,239	1,966	1,694	1,498	1,339	1,160	973	804
Net Annual Oil Production to repsol	**MMstb**	**9.4**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	587	99	85	68	53	47	44	39	36	35	32	27	23
Net Opex to Repsol	MMUS$	(312)	(26)	(33)	(27)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(35)	(3)	(9)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(47)	(18)	(9)	(6)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(3)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(25)	(7)	(4)	(3)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	4	0	0	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	0	0	0	0	0	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**147**	**40**	**29**	**22**	**19**	**15**	**12**	**10**	**8**	**2**	**4**	**(3)**	**(10)**
NPV @ 10% Net to Repsol	**MMUS$**	**123**												

2PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		519	497	432	379	335	298	267
Gross Annual Oil & Condensate Production	MMstb	**1.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	17	3	3	3	2	2	2	2
Repsol's Share of Profit Oil	MMUS$	9	2	2	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	222	212	184	162	143	127	114
Net Annual Oil Production to repsol	MMstb	**0.4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	25	5	5	4	3	3	3	3
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**2**	**2**	**2**	**1**	**(0)**	**(2)**	**1**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**3**							

2PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(10)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		198	215	191	146	115	93	76
Gross Condensate Production	Bcpd		4,091	6,767	6,744	5,221	4,222	3,399	2,732
Gross Oil Production	Bopd		12,067	12,342	15,038	13,019	12,239	9,539	7,443
Gross Annual Gas Production	**Bscf**	**377.5**	**72**	**78**	**70**	**53**	**42**	**34**	**28**
Gross Annual Condensate Production	**MMstb**	**12.1**	**1**	**2**	**2**	**2**	**2**	**1**	**1**
Gross Annual Oil Production	**MMstb**	**29.8**	**4**	**5**	**5**	**5**	**4**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	643	95	111	112	96	88	78	64
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	220	44	44	43	29	25	19	16
Net Entitlement to Repsol			21%	22%	22%	23%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		42	47	42	33	26	22	18
Net Condensate Production to Repsol	Bcpd		873	1,484	1,471	1,176	957	785	633
Net Oil Production to Repsol	Bopd		2,574	2,707	3,281	2,932	2,774	2,204	1,724
Net Annual Gas Production to Repsol	**Bscf**	**83.6**	**15**	**17**	**15**	**12**	**10**	**8**	**6**
Net Annual Condensate Production to Repsol	**MMstb**	**2.7**	**0**	**1**	**1**	**0**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**6.6**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	863	139	155	154	125	113	97	80
Net Opex to Repsol	MMUS$	(522)	(69)	(77)	(77)	(76)	(75)	(75)	(74)
Net Capex to Repsol	MMUS$	(77)	(17)	(48)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(4)	(1)	(1)	(1)	(1)	(1)	(0)	(0)
Overhead Payment from Partner	MMUS$	21	3	5	2	3	2	3	3
Net Export Duty-Repsol	MMUS$	(9)	(1)	(2)	(2)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(49)	(6)	(6)	(20)	(9)	(7)	(2)	0
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**170**	**46**	**16**	**45**	**26**	**22**	**16**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**142**							

2P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		12,983	12,254	11,209	8,771	7,002	5,698	4,685	3,964	3,336	2,842	2,361	1,942
Gross Annual Oil Production	**MMstb**	**28.1**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**1**	**1**	**1**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	379	29	70	39	28	28	29	27	27	31	28	24	20
Repsol's Share of Unused & Profit Oil	MMUS$	293	70	38	47	36	27	21	16	13	8	7	6	5
Net Entitlement to Repsol			33%	41%	36%	36%	37%	39%	40%	41%	45%	45%	45%	45%
Net Oil Production to Repsol	Bopd	11	4,314	4,974	4,054	3,152	2,610	2,225	1,879	1,642	1,501	1,274	1,062	874
Net Annual Oil Production to repsol	**MMstb**	**10.8**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	672	99	108	85	64	55	49	43	40	39	35	30	25
Net Opex to Repsol	MMUS$	(314)	(26)	(33)	(27)	(26)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(60)	(3)	(35)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(55)	(18)	(8)	(9)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(3)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(29)	(7)	(4)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)	(0)
Overhead Payment from partner	MMUS$	4	0	1	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(4)	0	0	0	0	0	0	(1)	(2)	(0)	(2)	0	0
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**188**	**40**	**27**	**34**	**27**	**21**	**16**	**12**	**9**	**5**	**5**	**(1)**	**(8)**
NPV @ 10% Net to Repsol	**MMUS$**	**150**												

2P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		519	497	432	379	335	298	267
Gross Annual Oil & Condensate Production	MMstb	**1.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	17	3	3	3	2	2	2	2
Repsol's Share of Profit Oil	MMUS$	9	2	2	1	1	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	0	222	212	184	162	143	127	114
Net Annual Oil Production to repsol	MMstb	**0.4**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	25	5	5	4	3	3	3	3
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**2**	**2**	**2**	**1**	**(0)**	**(2)**	**1**	**(1)**
NPV @ 10% Net to Repsol	**MMUS$**	**3**							

2P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(10)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

3PD – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		244	278	260	215	181	154	133
Gross Condensate Production	Bcpd		4,722	7,907	8,108	6,834	5,812	5,002	4,340
Gross Oil Production	Bopd		13,106	11,873	10,782	9,843	8,957	8,193	7,512
Gross Annual Gas Production	**Bscf**	**535.2**	**89**	**101**	**95**	**79**	**66**	**56**	**49**
Gross Annual Condensate Production	**MMstb**	**15.6**	**2**	**3**	**3**	**2**	**2**	**2**	**2**
Gross Annual Oil Production	**MMstb**	**25.6**	**5**	**4**	**4**	**4**	**3**	**3**	**3**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	641	86	99	97	97	93	87	81
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	297	60	61	53	37	31	29	25
Net Entitlement to Repsol			19%	20%	20%	22%	23%	23%	23%
Net Gas Production to Repsol	MMscfd		47	55	53	48	41	35	30
Net Condensate Production to Repsol	Bcpd		910	1,570	1,658	1,508	1,315	1,130	991
Net Oil Production to Repsol	Bopd		2,527	2,358	2,205	2,172	2,026	1,850	1,716
Net Annual Gas Production to Repsol	**Bscf**	**112.9**	**17**	**20**	**19**	**17**	**15**	**13**	**11**
Net Annual Condensate Production to Repsol	**MMstb**	**3.3**	**0**	**1**	**1**	**1**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**5.4**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	937	146	160	151	134	124	115	107
Net Opex to Repsol	MMUS$	(554)	(73)	(83)	(83)	(81)	(81)	(77)	(76)
Net Capex to Repsol	MMUS$	(17)	(2)	(3)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(58)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Overhead Payment from Partner	MMUS$	18	2	2	2	3	2	2	3
Net Export Duty-Repsol	MMUS$	(11)	(2)	(2)	(2)	(1)	(1)	(1)	(1)
Net PITA-Repsol	MMUS$	(77)	(11)	(19)	(17)	(11)	(9)	(9)	(1)
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**241**	**57**	**44**	**39**	**29**	**24**	**25**	**22**
NPV @ 10% Net to Repsol	**MMUS$**	**196**							

3PD – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		14,859	12,726	10,996	9,599	8,383	7,380	6,525	5,805	5,107	4,519	3,990	3,574
Gross Annual Oil Production	**MMstb**	**34.1**	**5**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**2**	**2**	**1**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	368	29	43	38	28	27	28	27	27	32	27	30	32
Repsol's Share of Unused & Profit Oil	MMUS$	415	82	56	46	41	36	31	28	26	21	21	16	12
Net Entitlement to Repsol			33%	36%	36%	35%	36%	37%	37%	37%	40%	38%	41%	43%
Net Oil Production to Repsol	Bopd	12	4,847	4,558	3,979	3,377	2,999	2,703	2,404	2,169	2,024	1,738	1,626	1,541
Net Annual Oil Production to repsol	**MMstb**	**12.4**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	783	111	99	84	68	63	60	55	52	53	48	45	44
Net Opex to Repsol	MMUS$	(310)	(26)	(32)	(27)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(35)	(3)	(9)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(74)	(21)	(12)	(8)	(6)	(5)	(4)	(4)	(3)	(3)	(3)	(2)	(1)
Net Research Cess payment	MMUS$	(4)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(6)	(6)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(42)	(8)	(6)	(5)	(4)	(4)	(3)	(3)	(3)	(2)	(2)	(2)	(1)
Overhead Payment from partner	MMUS$	4	0	0	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(40)	0	0	0	(1)	(6)	(5)	(6)	(6)	(4)	(5)	(4)	(2)
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**259**	**47**	**39**	**33**	**30**	**21**	**19**	**16**	**14**	**12**	**11**	**9**	**7**
NPV @ 10% Net to Repsol	**MMUS$**	**191**												

3PD – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		598	606	558	517	478	445	414
Gross Annual Oil & Condensate Production	MMstb	**1.3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	22	4	4	3	3	3	3	3
Repsol's Share of Profit Oil	MMUS$	12	2	2	2	2	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	1	255	259	238	221	204	190	177
Net Annual Oil Production to repsol	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	34	6	6	5	4	4	4	4
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**10**	**3**	**3**	**2**	**1**	**(1)**	**2**	**0**
NPV @ 10% Net to Repsol	**MMUS$**	**9**							

3PD – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

3P – PM3 CAA PSC

PM3CAA PSC (35%) - PSC Expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Gas Production	MMscfd		244	287	271	221	185	158	137
Gross Condensate Production	Bcpd		4,722	8,400	8,845	7,414	6,277	5,328	4,567
Gross Oil Production	Bopd		13,100	14,636	19,406	18,192	17,167	13,538	10,755
Gross Annual Gas Production	**Bscf**	**549.2**	**89**	**105**	**99**	**81**	**68**	**58**	**50**
Gross Annual Condensate Production	**MMstb**	**16.6**	**2**	**3**	**3**	**3**	**2**	**2**	**2**
Gross Annual Oil Production	**MMstb**	**39.0**	**5**	**5**	**7**	**7**	**6**	**5**	**4**
Realized Gas Price	US$/MMBtu		4	4	4	3	4	4	4
Realized Condensate Price	US$/bbl		63	60	58	56	58	61	63
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	725	102	131	116	101	97	89	88
Profit & Unused Oil + Gas + Con share to Repsol	MMUS$	364	55	61	70	55	49	42	32
Net Entitlement to Repsol			21%	22%	20%	20%	20%	20%	22%
Net Gas Production to Repsol	MMscfd		51	62	53	44	37	32	30
Net Condensate Production to Repsol	Bcpd		978	1,809	1,734	1,458	1,248	1,087	996
Net Oil Production to Repsol	Bopd		2,714	3,151	3,805	3,578	3,413	2,763	2,346
Net Annual Gas Production to Repsol	**Bscf**	**112.5**	**18**	**23**	**19**	**16**	**13**	**12**	**11**
Net Annual Condensate Production to Repsol	**MMstb**	**3.4**	**0**	**1**	**1**	**1**	**0**	**0**	**0**
Net Annual Oil Production to Repsol	**MMstb**	**7.9**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	1,089	157	192	186	157	146	131	120
Net Opex to Repsol	MMUS$	(572)	(73)	(84)	(87)	(85)	(85)	(80)	(78)
Net Capex to Repsol	MMUS$	(77)	(17)	(48)	(2)	(2)	(2)	(3)	(3)
Net Abex (Wells + Facilities) to Repsol	MMUS$	(59)	(5)	(11)	(10)	(13)	(8)	(6)	(6)
Net Supplementary Payment- Repsol	MMUS$	0	0	0	0	0	0	0	0
Net Research Cess payment-Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Overhead Payment from Partner	MMUS$	20	3	4	3	3	2	2	3
Net Export Duty-Repsol	MMUS$	(15)	(2)	(2)	(3)	(3)	(3)	(2)	(1)
Net PITA-Repsol	MMUS$	(105)	(10)	(17)	(27)	(17)	(15)	(13)	(5)
One-time extension bonus payment	MMUS$	8	1	1	1	1	1	4	0
Free Cash Flows to Repsol (PM3CAA)	**MMUS$**	**284**	**54**	**34**	**58**	**40**	**35**	**33**	**29**
NPV @ 10% Net to Repsol	**MMUS$**	**224**							

3P – KINABALU PSC

Kinabalu PSC (60%) - PSC expiry 2032	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		14,859	15,182	14,644	12,002	10,016	8,516	7,331	6,437	5,563	4,845	4,224	3,751
Gross Annual Oil Production	**MMstb**	**39.2**	**5**	**6**	**5**	**4**	**4**	**3**	**3**	**2**	**2**	**2**	**2**	**1**
Realized Oil Price	US$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Cost Recovery to Repsol	MMUS$	396	29	70	38	28	28	29	27	27	32	27	30	33
Repsol's Share of Unused & Profit Oil	MMUS$	490	82	57	68	55	45	39	34	30	24	24	19	14
Net Entitlement to Repsol			33%	38%	34%	34%	35%	36%	36%	37%	39%	38%	41%	43%
Net Oil Production to Repsol	Bopd	14	4,847	5,808	5,037	4,078	3,476	3,035	2,639	2,353	2,157	1,835	1,732	1,627
Net Annual Oil Production to repsol	**MMstb**	**14.1**	**2**	**2**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Net Revenue to Repsol	MMUS$	885	111	127	106	83	73	67	61	57	56	50	48	46
Net Opex to Repsol	MMUS$	(312)	(26)	(32)	(27)	(26)	(26)	(26)	(25)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(60)	(3)	(35)	(11)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells + facilities) to Repsol	MMUS$	(17)	0	(2)	0	0	0	(1)	0	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(86)	(21)	(13)	(12)	(8)	(6)	(5)	(5)	(4)	(4)	(4)	(3)	(2)
Net Research Cess payment	MMUS$	(4)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(6)	(6)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(49)	(8)	(6)	(7)	(5)	(5)	(4)	(3)	(3)	(2)	(2)	(2)	(1)
Overhead Payment from partner	MMUS$	4	0	1	0	0	0	0	0	0	0	0	0	0
Net PITA	MMUS$	(61)	0	0	(2)	(11)	(9)	(7)	(7)	(7)	(5)	(6)	(5)	(3)
Free Cash Flows to Repsol (Kinabalu)	**MMUS$**	**293**	**47**	**40**	**47**	**31**	**26**	**23**	**19**	**17**	**14**	**12**	**10**	**8**
NPV @ 10% Net to Repsol	**MMUS$**	**215**												

3P – B46 PSC

Block 46 PSC (70%) - PSC expiry 2027	Unit	Total	2021	2022	2023	2024	2025	2026	2027
Gross Oil & Condensate Production Rate	Bopd		598	606	558	517	478	445	414
Gross Annual Oil & Condensate Production	MMstb	**1.3**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56	58	61	63
Cost Recovery to Repsol	MMUS$	22	4	4	3	3	3	3	3
Repsol's Share of Profit Oil	MMUS$	12	2	2	2	2	1	1	1
Net Entitlement to Repsol			43%	43%	43%	43%	43%	43%	43%
Net Oil Production to Repsol	Bopd	1	255	259	238	221	204	190	177
Net Annual Oil Production to repsol	MMstb	**0.6**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	34	6	6	5	4	4	4	4
Net Opex to Repsol	MMUS$	(16)	(3)	(2)	(2)	(2)	(2)	(2)	(2)
Net Capex to Repsol	MMUS$	(0)	(0)	0	0	0	0	0	0
Net Abex (Wells + facilities) to Repsol	MMUS$	(7)	0	0	(1)	(1)	(3)	0	(2)
Net Export Duty	MMUS$	0	0	0	0	0	0	0	0
Overhead Payment from partner	MMUS$	0	0	0	0	0	0	0	0
Net Corporate Income Tax	MMUS$	0	0	0	0	0	0	0	0
Free Cash Flows to Repsol (Block 46)	**MMUS$**	**10**	**3**	**3**	**2**	**1**	**(1)**	**2**	**0**
NPV @ 10% Net to Repsol	**MMUS$**	**9**							

3P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

3P – PM305/PM314 PSC

PM305/PM314 PSC (60%) - PSC expiry 2024	Unit	Total	2021	2022	2023	2024
Gross Oil Production Rate	Bopd		380	300	270	240
Gross Annual Oil Production	**MMstb**	**0.4**	**0**	**0**	**0**	**0**
Realized Oil Price	USD/bbl		63	60	58	56
Cost Recovery to Repsol	MMUS$	8	3	2	2	1
Repsol's Share of Profit Oil	MMUS$	4	1	1	1	1
Net Entitlement to Repsol			44%	44%	44%	44%
Net Oil Production to Repsol	Bopd	0	169	133	120	107
Net Annual Oil Production to Repsol	**MMstb**	**0.2**	**0**	**0**	**0**	**0**
Net Revenue to Repsol	MMUS$	11	4	3	3	2
Net Opex to Repsol	MMUS$	(5)	(1)	(1)	(1)	(1)
Net Capex to Repsol	MMUS$	(1)	(0)	(0)	(0)	(0)
Net Abex (Wells + facilities) to Repsol	MMUS$	(15)	(13)	(2)	0	0
Supplementary Payment	MMUS$	(0)	(0)	(0)	(0)	0
Research Cess	MMUS$	(0)	(0)	(0)	(0)	(0)
Net Export Duty	MMUS$	(0)	(0)	(0)	(0)	(0)
Overhead Payment from partner	MMUS$	0	0	0	0	0
PITA	MMUS$	0	0	0	0	0
Free Cash Flows to Repsol (PM305)	**MMUS$**	**(9)**	**(10)**	**(1)**	**1**	**1**
NPV @ 10% Net to Repsol	**MMUS$**	**(10)**				

2P – Consolidated of Assets

Consolidated	Unit	Total	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Gross Oil Production Rate	Bopd		25,950	25,393	26,948	22,409	19,576	15,535	12,396	3,964	3,336	2,842	2,361	1,942
Gross Condensate Production	Bopd		4,091	6,767	6,744	5,221	4,222	3,399	2,732	0	0	0	0	0
Gross Gas Production	MMscfd		198	215	191	146	115	93	76	0	0	0	0	0
Gross Annual Oil Production	MMstb	59	9	9	10	8	7	6	5	1	1	1	1	1
Gross Annual Condensate Production	MMstb	12	1	2	2	2	2	1	1	0	0	0	0	0
Gross Annual Gas Production	Bscf	378	72	78	70	53	42	34	28	0	0	0	0	0
Net Entitlement to Kinabalu- PSC			33%	41%	36%	36%	37%	39%	40%	41%	45%	45%	45%	45%
Net Entitlement to PM3CAA PSC			21%	22%	22%	23%	23%	23%	23%	0%	0%	0%	0%	0%
Net Oil Production to Repsol	Bopd		7,279	8,027	7,639	6,352	5,527	4,556	3,717	1,642	1,501	1,274	1,062	874
Net Condensate Production to Repsol	Bcpd		873	1,484	1,471	1,176	957	785	633	0	0	0	0	0
Net Gas Production to Repsol	MMscfd		42	47	42	33	26	22	18	0	0	0	0	0
Net Oil+ Condensate + Gas Production Rate	Boepd		15,198	17,364	16,056	12,994	10,838	8,937	7,285	1,642	1,501	1,274	1,062	874
Net Annual Oil Production to Repsol	MMstb	18	3	3	3	2	2	2	1	1	1	0	0	0
Net Annual Condensate Production to Repsol	MMstb	3	0	1	1	0	0	0	0	0	0	0	0	0
Net Annual Gas Production to Repsol	Bscf	84	15	17	15	12	10	8	6	0	0	0	0	0
Realized Oil Price	$/bbl		63	60	58	56	58	61	63	66	71	75	77	78
Realized Condensate Price	$/bbl		63	60	58	56	58	61	63	0	0	0	0	0
Realized Gas Price	$/mmbtu		3.9	3.7	3.6	3.5	3.6	3.9	4.0	0.0	0.0	0.0	0.0	0.0
Cost Recovery to Repsol	MMUS$	1,047	131	186	154	127	118	108	93	27	31	28	24	20
Repsol's Share of Profit and Unused Cost Liquid & Gas	MMUS$	525	117	85	92	66	53	41	33	13	8	7	6	5
Net Revenue to Repsol	MMUS$	1,571	247	271	246	194	170	149	126	40	39	35	30	25
Net Opex to Repsol	MMUS$	(857)	(99)	(113)	(108)	(105)	(103)	(103)	(101)	(25)	(25)	(25)	(25)	(25)
Net Capex to Repsol	MMUS$	(138)	(20)	(82)	(13)	(4)	(4)	(4)	(4)	(1)	(1)	(1)	(1)	(1)
Net Abex (Wells & Facilities) to Repsol	MMUS$	(99)	(18)	(15)	(11)	(14)	(11)	(7)	(8)	0	(5)	0	(3)	(6)
Net Supplementary Payment	MMUS$	(55)	(18)	(9)	(9)	(5)	(4)	(3)	(2)	(2)	(1)	(1)	(1)	(1)
Net Research Cess payment	MMUS$	(8)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)
Sabah Sales Tax	MMUS$	(5)	(5)	0	0	0	0	0	0	0	0	0	0	0
Net Export Duty	MMUS$	(39)	(9)	(5)	(6)	(5)	(4)	(3)	(2)	(1)	(1)	(1)	(1)	(0)
Net PITA-Repsol	MMUS$	(53)	(6)	(6)	(20)	(9)	(7)	(2)	(1)	(2)	(0)	(2)	0	0
Overhead Payment from Partner	MMUS$	25	4	5	3	3	3	3	3	0	0	0	0	0
One-time extension bonus payment (PM3CAA)	MMUS$	8	1	1	1	1	1	4	0	0	0	0	0	0
Net Project Free Cash Flows	**MMUS$**	**351**	**77**	**45**	**81**	**54**	**41**	**32**	**10**	**9**	**5**	**5**	**(1)**	**(8)**
NPV @ 10% Net to Repsol	**MMUS$**	**285**												

Contact

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LETTER OF POLICIES ON FOREIGN INVESTMENTS, REPATRIATION OF PROFITS, TAXATION AND ANTI-AVOIDANCE IN BARBADOS

Private & Confidental

Hibiscus Petroleum Berhad
2nd Floor, Syed Kechik Foundation Building
Jalan Kapas, Bangsar
59100 Kuala Lumpur

1 June 2021

Dear Sirs

LETTER OF POLICIES ON FOREIGN INVESTMENTS, REPATRIATION OF PROFITS, TAXATION AND ANTI-AVOIDANCE IN BARBADOS

We have been requested to provide our professional statement, summary information and the current policies regarding the restrictions on foreign investment, repatriation of profits, taxation and anti-avoidance in Barbados ("the Professional Statement") in connection with the proposed acquisition of Fortuna International Petroleum Corporation which owns 100% interest in each of the following Barbados entities:

- Repsol Oil & Gas Malaysia Limited;
- Repsol Oil & Gas Malaysia (PM3) Limited; and
- Talisman Vietnam Limited ("TVL")

The Professional Statement has been prepared on the basis of laws and policies that are in force in Barbados at the date of this letter. The laws are subject to change and may impact our statement materially. The text below is a brief summary and therefore, limited to a general overview. It does not cover every aspect of investments and cannot provide information regarding individual circumstances. The information given in this memorandum is limited to the tax regulations and does not constitute legal advice.

(Please note that PricewaterhouseCoopers Taxation Services Sdn Bhd is not permitted to provide legal services and legal advice, and therefore our comments below on the policies on foreign investment and repatriation of profits of Barbados are general comments only.)

PART I – Restrictions on foreign investment and repatriation of profits

Other than the exchange control restrictions discussed in A. and B. below, Barbados does not impose any restrictions on the repatriation of profits.

A. Barbados Exchange Control Act Cap. 71

Generally, resident companies in Barbados may not make or receive payments in a foreign currency or operate a bank account in a foreign currency without the approval of the Exchange Control Authority.

Pursuant to section 4(1) of the Exchange Control Act, *"Except with the permission of the Authority, no person, other than an authorised dealer, shall, in the Island, buy or borrow any gold or* ***foreign currency*** *from, or sell or lend any gold or foreign currency to, any person other than an authorised dealer."*

PricewaterhouseCoopers Taxation Services Sdn Bhd (464731-M),
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Pursuant to section 4(4) of the Exchange Control Act *"In this Act, "foreign currency" means any currency other than the Barbados dollar which is or has at any time been legal tender in any place outside Barbados and any reference to foreign currency, except so far as the context otherwise requires, includes a reference to a right to receive foreign currency in respect of any credit or balance at a bank or other institution."*

Pursuant to section 9(1) of the Exchange Control Act, *"Except with the permission of the Authority, no person resident in Barbados shall, subject to this section, in the Island do any act which involves, is in association with or is preparatory to, the making of any payment outside the Island to or for the credit of a person resident outside Barbados."*

B. Foreign Currency Permit Act 2018-44.

Pursuant to section 9 of the Foreign Currency Permit Act 2018-44, *"The Exchange Control Act, Cap. 71 does not apply to a company granted a permit under this Act."*

A company which earns 100% of its income in foreign currency, may apply to the Director of International Business for the grant of a Foreign Currency Permit by providing the following:
- applicable fee;
- completed application form;
- in the case of an initial application, a declaration in the prescribed form certifying that the entity intends to earn 100% of its income in foreign currency and in the case of a Foreign Currency Permit renewal, an executed declaration certifying that 100% of the applicant's income for the relevant financial year was earned in foreign currency based on its audited financial statements for the preceding year.

A Foreign Currency Permit remains valid for 12 months unless cancelled or revoked by the Director.

PART II – Taxation in Barbados

C. Corporate tax

Pursuant to section 5 of the Barbados Income Tax Act, *"Subject to this Act, the assessable income of a person is his income from all sources, whether within or outside Barbados, and, without restricting the generality of the foregoing, includes income from all*
(a) business;
(b) property;
(c) offices; and
(d) employments."

Companies resident in Barbados are taxed on income earned from all sources, whether generated within or outside of Barbados, less expenses incurred for the purpose of producing assessable income in a fiscal period.

The following tax rates apply to resident entities:
- 5.5% on taxable income up to US$0.5M;
- 3.0% on taxable income exceeding US$0.5M but not exceeding US$10M;
- 2.5% on taxable income exceeding US$10M but not exceeding US$15M; and
- 1% on taxable income in excess of US$15M.

Hibiscus Petroleum Berhad
1 June 2021

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D. Dividend income

Dividends between two resident companies in Barbados are not taxed in the hands of the recipient. Dividends received by a resident company in Barbados, from a non-resident entity where the equity interest owned is at least 10% of the non-resident company and the shareholding is not held solely for the purpose of portfolio investments are not subject to tax in Barbados.

Section 65(4E) of the Barbados Income Tax Act ("BITA") states that dividends paid by a regular business company to a non-resident shareholder are not subject to withholding tax when the amount paid as dividends is derived from income earned from sources outside of Barbados.

Pursuant to section 65(4) of the BITA, dividends paid out of domestic sourced income are subject to a 5 per cent withholding tax in Barbados.

E. Withholding taxes

Pursuant to Regulations 90 and 90(B) of the BITA, amounts paid to non-resident persons as interests or royalties are exempt from withholding taxes in Barbados.

In addition, pursuant to Regulation 93A(A), fees or charges for the provision of management or administrative services are subject to 0% withholding tax. This is where the service is performed in Barbados by a non-resident person.

In accordance with the BITA, management fees paid or payable to a non-resident is not deductible in the calculation of assessable income.

Management fees as defined in the BITA is *a fee or charge for management and or administrative services provided by a member of a group of companies to other members of the group."*

In summary, the scope of the definition of *"management fees"* has been narrowed and limited to management and administrative services rendered between related parties only. In consequence, services other than management and administrative services rendered to unrelated parties, will be subject to withholding taxes in Barbados at the rate of 15% and the amounts paid claimed as deductions in Barbados.

F. Foreign tax credits

Pursuant to section 83A(4) of the BITA, *"The total credit for foreign tax to be allowed to a person in respect of any income year under any agreement to which this Part applies shall not reduce the total tax payable by the person on his own behalf for that income year to less than 1 per cent."*

G. Tax Losses

Tax losses can generally be carried forward for seven years after the income year in which they are incurred.

With effect from income year 2019, tax losses brought forward available for offset in an income year is restricted to 50% of the taxable income in the year in which the tax loss is utilised.

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H. Stamp duty

Pursuant to the Schedule of the Stamp Duty Act Cap.91, resident companies are exempt from the application of the Act when *"All instruments by which shares in a company are transferred to a person who is a resident outside Barbados, whether or not the transfer is effected by a person who is resident in Barbados if*

(a) the assets of the company consist of foreign assets, including investments comprising shares and securities in foreign companies, and

(b) the income of the company is derived solely from sources outside of Barbados."

Furthermore, pursuant to the Stamp Duty (Amendment) Act 2018-48, *"The holder of a foreign currency permit under the Foreign Currency Permits Act, 2018 (Act 2018-44), is exempt from ad valorem stamp duty except in respect of real property situate in Barbados, but shall pay a fixed rate as specified in this Schedule."*

I. Property transfer tax

Please note that any transfer of shares to a person who is resident outside of Barbados, whether or not the transferor is resident in Barbados, where the assets of the company concerned consists of foreign assets and its income is derived solely from sources outside Barbados, will not be subject to transfer taxes in Barbados.

In accordance with Section 6(1) of the Property Transfer Tax Act. Cap.84A, the following are exempt from property transfer tax:

- any transfer of property consisting of shares issued by or on behalf of a company that holds a foreign currency permit issued under the Foreign Currency Permit Act; and
- any transfer of property consisting of shares issued by or on behalf of a qualifying insurance company which satisfies certain condition and that are traded on a recognised securities exchange.

PART III - Anti-avoidance rules

J. Thin capitalization rules

Pursuant to section 11(2A) of the BITA, *"With effect from 1st September, 2019, interest payable on outstanding debts due to a non-resident related party that owns more than 10 per cent of the company shall be deductible to the extent that the total amount of the debt does not exceed one and a half times the equity of the company."*

K. Artificial transactions provision

The BITA contains an artificial transaction provision which requires intra-group transactions to take place at arm's length or at a fair market value. Although, the main purpose of this provision is preventing the artificial reduction of the assessable income of Barbados resident persons.

Pursuant to section 29(2) of the BITA: "*Where the main purpose of a transaction is the artificial reduction of the assessable income of a person, then, in calculating the assessable income of the persons participating in the transaction and solely for the purposes of this Act and other enactments relating to income tax, that transaction shall be disregarded or shall be deemed to be modified, whichever is* *more appropriate to achieve the effect that the transaction no longer results in an artificial reduction of the assessable income of that person."*

L. Economic substance

In November 2018, the Organisation for Economic Cooperation and Development (the "OECD") Inclusive Framework released a publication entitled *"Resumption of Application of Substantial Activities Factor to No or only Nominal Tax Jurisdictions"*. The main purpose of this document is to prevent zero and low tax jurisdictions from attracting profits from certain geographically mobile activities without corresponding economic activities. In response to this OECD initiative, Barbados enacted the Business Companies (Economic Substance) Act, 2018, which has now been repealed and replaced by the Companies (Economic Substance) Act 2019-43 ('the Act') which is in turn supported by the Economic Substance Guidelines Version 1.2 ('the Guidelines'). The Guidelines provide support for understanding the scope and application of the Act. The Act was passed on November 29, 2019 and requires a resident entity which derives income from carrying on a relevant activity to satisfy the economic substance test in relation to that relevant activity.

A relevant activity encompasses any of the following categories of business:
- banking business;
- insurance business;
- fund management business;
- finance and leasing business;
- headquarters business;
- shipping business;
- holding company business;
- intellectual property business;
- distribution and service center business; and
- such other activities as the Minister may by order prescribe.

A resident company carrying on any of the above relevant activities, which is not tax resident in another jurisdiction, must, in relation to that relevant activity, meet the economic substance test. The economic substance test will assess the extent to which the entity conducts its core income generating activities and is directed, managed and controlled in Barbados in relation to that relevant activity in Barbados, specifically:
- whether adequate meetings are held and attended by the board of directors in Barbados; and
- having regard to the level of relevant activity carried on in Barbados whether:
    - an adequate number of qualified full-time employees were physically present in Barbados in relation to that activity;
    - adequate operating expenditure was incurred in Barbados; and
    - adequate physical assets exist in Barbados.

Limitations

You should note that our advice represents our views on Barbados taxes based on our analysis at the date of this letter. This advice is not binding on the local tax or regulatory authorities. Our advice on Barbados taxes is based on the applicable provisions of the Barbados Income Tax Act, Foreign Currency Permit Act, Stamp Duty Act, Exchange Control Act, Property Transfer Tax Act, Companies (Economic Substance) Act and regulations thereunder in force as at the date of preparation of this letter, our understanding of the administrative practices of the Barbados Revenue Authority and proposed amendments to these Acts publicly announced by the Ministry of Finance of Barbados. Any changes to

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these statutes may or may not be retroactive with respect to the proposed transaction and could affect the advice expressed in this Professional statement.

Notes to this Professional Statement

This Professional Statement is based on the completeness and accuracy of the facts and / or reprentation provided by you. If any of the aforementioned facts, representations or assumptions is not entirely complete or accurate, it is imperative that we be informed immediately, as inaccuracy and incompleteness could have a material effect on the validity of this Professional Statement.

This Professional Statement reflects our interpretation of the applicable laws and the corresponding jurisprudence.

This Professional Statement is prepared based on the current tax laws in Barbados and is subject to changes in such laws, or on the interpretation thereof. Such changes may be restrospective. While the comments are considered to be a correct interpretation of existing laws in force as at the latest practicable date, no assurance can be given that courts or fiscal authorities responsible for the administration of such laws will agree with this interpretation or that changes in such laws will not occur.

We have no obligation to update the contents of this Professional Statement as laws or practices change, unless specifically requested to do so.

No inference beyond their normal meaning should be drawn from the is of the words "will", "should", etc as they relate to the relative strengths of a particular position outlined in the document.

This Professional Statement, which would be included in the circular and be distributed to the shareholders of Hibiscus Petroleum Berhas, was prepared solely for Hibiscus Petroleum Berhad on the basis of the engagement letter concluded between Hibiscus Petroleum Berhad and ourselves. Third parties' notice of its content is entirely at their own risk.

We have no obligation, responsibility or duty of care towards third parties (reliance restricted), unless otherwise confirmed to a third party in advance in writing.

Yours faithfully

Lavindran Sandragasu
Partner

Ref: LS/AP/SS/nas

LEGAL OPINION ON THE OWNERSHIP OF TITLE TO THE SHARES OF FIPC UNDER THE LAWS OF BARBADOS

HSC | HAMEL-SMITH CARIBBEAN

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October 4, 2021

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Malaysia

LEGAL OPINION – OWNERSHIP/TITLE TO SHARES OF FORTUNA INTERNATIONAL PETROLEUM CORPORATION UNDER BARBADOS LAWS

BACKGROUND

We are lawyers qualified to practice, advise and opine on Barbados laws. We have been instructed by Hibiscus Petroleum Berhad ("**Hibiscus**") to issue a legal opinion (the "**Opinion**") on the above subject matter. This Opinion is issued in relation to the proposed acquisition by Peninsula Hibiscus Sdn Bhd of Fortuna International Petroleum Corporation ("**Fortuna**" or "**Target**"). By virtue of a Sale and Purchase Agreement dated June 1, 2021 Peninsula Hibiscus Sdn Bhd intends to purchase 100% of the shares in Fortuna (the "**Proposed Acquisition**"), a company incorporated in Barbados with company number 41915, from Repsol Exploración, S.A. ("**Repsol**") (the "**SPA**").

We understand that this Opinion will be used for inclusion in the circular to shareholders of Hibiscus to be issued by Hibiscus in connection with the Proposed Acquisition (the "**Circular**").

INSTRUCTIONS

The scope of this Opinion is limited to Repsol's ownership and good legal title to the shares in Fortuna.

LAWS OF BARBADOS

This Opinion is confined to matters expressly opined on herein and given on the basis of the laws of Barbados and we have made no investigation of, and express no opinion on, the law of any other jurisdiction. This Opinion is governed and construed in accordance with the laws and regulations of Barbados as they are in force and applied by the Barbados courts at the date of this Opinion.

DOCUMENTS EXAMINED

For the purpose of giving this Opinion, we have examined the following documents:

I. The executed SPA;

II. Certificate of Amalgamation of Fortuna dated August 31, 2017 and issued by the Registrar of Companies in Barbados;

III. Articles of Amalgamation of Fortuna dated August 31, 2017 as amended by Articles of Amendment dated March 2, 2018 (the "**Articles**");

IV. Certificate of Amendment dated March 2, 2018;

V. Share Certificate(s) Number 2 held by Repsol dated December 16, 2020 (the "**Share Certificate**");

VI. Fortuna's Share Register (the "**Share Register**");

VII. Fortuna's International Business Licence dated February 1, 2021 issued by the Director of International Business in Barbados (the "**IBC Licence**")

VIII. Letter dated June 11, 2021 from Lex Caribbean, Attorneys-at-Law to the Exchange Control Authority of the Central Bank of Barbados seeking approval for the Proposed Acquisition. Letter contains approval stamp from the Exchange Control Authority dated June 29, 2021 (the "**ECA Approval**").

Except as mentioned above, we have not examined any other documents or made any enquiries in connection with the giving of this Opinion. On examination of the above documents, we have assumed the genuineness of all signatures and seals on all of the documents submitted to us, the authenticity of all documents submitted to us as originals, the conformity with the originals of all documents submitted to us as copies thereof are legal and valid under the applicable laws and regulations and that all documents have been executed in accordance with the relevant company's by-laws.

OPINION

Subject to the foregoing and the matters set out below and to any matters not disclosed to us, we opine as follows.

Legality and Ownership of Shares

In giving our Opinion on Repsol's ownership and title to the shares in Fortuna we have taken the following into consideration:

1. By the Articles, Fortuna is authorized to issue an unlimited number of shares of a class designated Class A Common Shares at no par value;
2. Schedule 1 of the SPA records the issued share capital of Fortuna as comprising 313,736,062 Class A Common Shares (the "**Shares**");
3. The Share Certificate and Share Register records Repsol as holding 313,736,062 Class A Common Shares in Fortuna;
4. By Schedule 4 of the SPA the Seller has warranted, inter alia, that the Shares constitute the whole of the issued share capital of Fortuna and that it is the sole legal and beneficial owner thereof;
5. In Barbados there is, at present, no obligation to record the shareholding of a company at our local Companies Registry. In the circumstances and in accordance with local practice, we accept the Share Certificate and Share Register as prima facie evidence of the ownership of the Shares. Similarly, reliance is placed on the Seller's warranties as given in the SPA.

In the premises, we are of the view that Repsol holds good legal title to all of the issued share capital of Fortuna in accordance with the terms of the SPA, the Share Register and the Share Certificate as supplied to us. Repsol holds the Share Certificates consistent with the records in Fortuna's Shareholder Register and there is no evidence that the Share Certificates contain any pledge, mortgage, lien or the like. Therefore, Repsol has the full legal and beneficial title to the respective shares and may transfer the full ownership of the respective shares to Hibiscus according to the applicable laws.

Exchange Control

Under the Exchange Control Act of Barbados, shares may not be *issued* to foreign residents without the approval of the Central Bank of Barbados unless those shares pertain to

International Business Companies which are exempt from the provisions of the said Act. We have accordingly assumed Fortuna's valid registration as an International Business Company based on the IBC Licence and therefore an exemption from the said requirement for approval as it relates to the issuing of the Shares.

Similarly, any subsequent *transfer* of shares to a foreign resident also requires the approval of the Central Bank of Barbados. However, International Business Companies and/or companies holding a "Foreign Currency Permit" (which we are instructed that Fortuna has applied for) are exempt from this requirement. Notwithstanding such exemption potentially applying to Fortuna, we are aware that approval for the transfer of the Shares from the Barbados Exchange Control Authority was nevertheless sought and subsequently granted as evidenced in the ECA Approval listed above.

In the circumstances we are of the view that there are no exchange control issues which could affect the title to the Shares and we are not aware of any other issues which could similarly affect such title.

BENEFIT OF THIS OPINION

This Opinion is given solely for the benefit of the persons to whom it is addressed and solely in connection with the Proposed Acquisition. This Opinion may not be relied upon for any other purpose or by any other person and may not be transmitted or disclosed to any other person or entity (including governmental agency or stock or other exchange) or filed with any person or entity or be quoted or referred to in any public document without our prior written consent, except:

I. that a copy of this Opinion may be disclosed to the legal advisors and other advisors of Hibiscus involved in the Proposed Acquisition;

II. that a copy of this Opinion will be attached to the Circular to be distributed to the shareholders of Hibiscus in relation to the Proposed Acquisition, which it is noted will be a publicly available document (including on the website of Bursa Malaysia Securities Berhad); and

III. that a copy of this Opinion may be submitted to Bursa Malaysia Securities Berhad as part of the relevant regulatory approval process in relation to the Proposed Acquisition; and

IV. as required by the laws or regulations of any country with jurisdiction over your affairs.

DISCLOSURES

Hamel-Smith Caribbean has given and has not subsequently withdrawn its written consent to the inclusion of its name, its legal opinion on certain matters of Barbadian law and all references thereto in the form and context in which they appear in the Circular. Hamel-Smith Caribbean hereby declares that there is no situation of conflict of interest that exists or likely to exist in relation to its provision of this legal opinion.

Yours Faithfully,

Benjamin D. Norris
Partner

LEGAL OPINION ON THE ENFORCEABILITY OF AGREEMENTS, REPRESENTATIONS AND UNDERTAKINGS GIVEN BY THE SELLER UNDER THE LAWS OF SPAIN

HERBERT SMITH FREEHILLS

To: **Hibiscus Petroleum Berhad**
2nd Floor
Syed Kechik Foundation Building
Jalan Kapas, Bangsar
59100 Kuala Lumpur
Malaysia

Attention: Board of Directors of Hibiscus Petroleum Berhad

(hereinafter, the "**Addressee**")

17 November 2021

Dear Sirs/Madams,

Ref.: Spanish law legal opinion on Repsol Exploración, S.A.

1. **INTRODUCTION**

1.1 We have issued this legal opinion at the request of, and in our capacity as Spanish counsel of, Hibiscus Petroleum Berhad ("**Hibiscus**"), on Repsol Exploración S.A., a company domiciled in Spain with Spanish tax number (*NIF*) A28138873 and registered office at Calle Méndez Álvaro, 44, 28045 Madrid (Spain) ("**Repsol**"), in connection with:

1.1.1 the sale and purchase agreement entered into on 1 June 2021 by Peninsula Hibiscus Sdn Bhd ("**Peninsula Hibiscus**"), as purchaser, and Repsol, as seller, for the proposed acquisition by Peninsula Hibiscus of the entire equity interest in Fortuna International Petroleum Corporation ("**FIPC**") from Repsol ("**Proposed Acquisition**") (the "**SPA**");

1.1.2 the parent company guarantee granted by Hibiscus for the benefit of Repsol on 1 June 2021 in order to secure the punctual performance and observance by Peninsula Hibiscus of all its obligations under the SPA (the "**Parent Company Guarantee**"); and

1.1.3 the transition services agreement entered into on 11 November 2021 between Peninsula Hibiscus and Repsol for the performance of transitional services by Repsol to Hibiscus Peninsula and FIPC and its subsidiaries (the "**Transition Services Agreement**").

1.2 For the purpose of this opinion, the SPA, the Parent Company Guarantee and the Transition Services Agreement shall be jointly referred to as the "**Relevant Documents**".

2. **SCOPE OF THIS OPINION**

2.1 We are lawyers qualified to practise, advise and opine on Spanish laws. This opinion is limited to Spanish law as applied by the Spanish courts and published and in effect on the date of this opinion. It is given on the basis that it (including all terms used in it) will be construed in accordance with Spanish law. Accordingly, we express no opinion with regard to any system of law other than the laws of Spain.

2.2 We do not give any opinion on any matters of fact (including but not limited to statements, covenants and representations and warranties as made by Repsol or contained in the Relevant Documents), matters of insurance, technical or taxation matters, treaties or international law.

HERBERT SMITH FREEHILLS

2.3 This opinion is strictly confined to the specific matters as expressly set out in section 5 below, and is not to be read as extending by implication to any other matter in connection with the Relevant Documents or otherwise.

2.4 This opinion and any non-contractual obligations arising out of or in connection with it are governed by and shall be construed in accordance with Spanish law. This opinion is given on condition that the courts of Spain have exclusive jurisdiction to settle any dispute or claim arising out of or in connection herewith (including any non-contractual disputes or claims).

2.5 This opinion is not designed to and is not likely to reveal fraud, misrepresentation, bribery or corruption by any person.

3. **DOCUMENTS EXAMINED**

3.1 For the purposes of this opinion, we have examined the following documents:

3.1.1 A scanned copy of the executed version of the Relevant Documents.

3.1.2 A PDF copy of a certificate of Repsol issued by the Commercial Registry of Madrid dated 5 July 2021, including, among others, a copy of Repsol's articles of association (*estatutos sociales*).

3.1.3 A PDF copy of an online literal excerpt of Repsol issued by the Commercial Registry of Madrid dated 17 November 2021.

3.1.4 Online search in the web page of the Public Registry of Bankruptcy Orders (*Registro Público Concursal*) made on 17 November 2021, informing that Repsol is not currently involved in any insolvency proceedings.

3.1.5 A PDF copy of the public deed pursuant to which Repsol has appointed for a six-years term, among others, Mr Tomás García Blanco (the "**Signatory**") as joint and several director (*administrador solidario*) of Repsol, granted on 23 December 2015 before the notary public of Madrid Mr Juan José de Palacio Rodríguez with number 2,176 of his official records pursuant to which the Signatory had at the relevant time sufficient faculties to execute the SPA and Parent Company Guarantee.

3.1.6 A PDF copy of the public deed pursuant to which Repsol has, among others, re-elected for a six-years term the Signatory as joint and several director (*administrador solidario*) of Repsol, granted on 6 October 2021 before the notary public of Madrid Mr Juan José de Palacio Rodriguez with number 7,907 of his official records pursuant to which the Signatory has sufficient faculties to execute the Transition Services Agreement. Furthermore, pursuant to the public deed described in this section, Repsol has approved the amendment of the articles of association and a new revised text of the current articles of association of Repsol.

3.2 In this opinion, the documents described in section 3.1 above shall be jointly referred to as the "**Documents**" and each of them, individually, as a "**Document**".

3.3 Except for the searches, inquiries, contacts or documents expressly indicated as reviewed in this legal opinion, we have not considered any searches or carried out any enquiries in relation to, nor we have examined contracts or agreements granted or entered into by, or that in any way whatsoever may affect any of the parties indicated in this legal opinion.

4. **ASSUMPTIONS**

4.1 For the purpose of this opinion, we have made the following assumptions:

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4.1.1 **Due incorporation**: all the legal entities that are party to the Relevant Documents (other than Repsol) are duly incorporated under its law of incorporation.

4.1.2 **Authenticity**: all Documents (including copy and scanned documents) examined by us are authentic and complete and all signatures and/or seals thereon are genuine.

4.1.3 **Effective documents**: all Documents which we have reviewed are and remain effective.

4.1.4 **Accuracy of Documents**: all Documents and Relevant Documents remain up-to-date and have not been modified, altered, revoked, cancelled or suspended in any way since the date of issuance of such Documents and Relevant Documents. For the purpose of this assumption, and notwithstanding the foregoing, we are assuming that the articles of association of Repsol included in the certificate mentioned in section 3.1.2 were up-to-date and in force on the execution date of the SPA and the Parent Company Guarantee; however, these have been amended pursuant to the public deed mentioned in section 3.1.63.1.5 and the articles of association included in the public deed mentioned in section 3.1.6 were in force on the date of the execution of the Transition Services Agreement and remain in force and up-to-date as of the date of this opinion.

4.1.5 **Public information and filings**: the public information and documentation available in the public registries (including the Commercial Registry) is complete, accurate and has been duly updated and, particularly, the online informative excerpt mentioned in sections 3.1.3 and 3.1.4.

4.1.6 **Capacity**: all the signatories of the Relevant Documents (other than Repsol) have the power and legal capacity to enter into, perform and exercise its rights under the Relevant Documents and the Relevant Documents have been duly authorised, executed and, where applicable, delivered by all of the signatories thereto in accordance with all applicable laws.

4.1.7 **Administration**: no step has been taken to obtain a moratorium in relation to any signatory of the Relevant Documents or to wind up any signatory or to place any signatory into administration and that no receiver has been appointed over or in respect of the assets of any signatory, nor has any analogous procedure or step been taken in any jurisdiction.

4.1.8 **Validity of obligations to be performed in foreign jurisdictions**: insofar as any obligations are required to be performed in any jurisdiction outside Spain, its performance will not be null, void, illegal, or ineffective by virtue of the laws of that jurisdiction.

4.1.9 **Provisions under foreign laws**: there is nothing under any law (other than the laws of Spain) which would or might affect this opinion. We have made no independent investigations of any laws other than the laws of Spain.

4.1.10 **Misconduct, etc.**: no party to the Relevant Documents is, or will be, engaging in misleading, deceptive or unconscionable conduct or seeking to conduct any relevant transaction or any associated activity in a manner or for a purpose not evident on the face of the Relevant Documents which might render the Relevant Documents or any transaction contemplated thereby or any associated activity illegal, void or voidable.

4.1.11 **No breach:** no signatory of the Relevant Documents will, by reason of the transactions contemplated by the Relevant Documents, be in breach of any of their respective obligations under any agreement, licence, authorisation, consent or similar document.

4.1.12 **Solvency**: at the date of this opinion and at the date of execution of the Relevant Documents: (1) Repsol is not unable to pay its debts according to article 2 et seq. of Spanish Royal Legislative Decree 1/2020 of 5 May, approving the recast version of the Insolvency Law (the "**Insolvency Law**"); (2) Repsol will not be unable to pay its debts according to article 2 of the Insolvency Law as a consequence of performing its obligations under the Relevant Documents; (3) no insolvency declaration has been filed with respect to Repsol; (4) Repsol has not made any of the notifications referred to in article 583 of the Insolvency Law; and (5) no liquidator or insolvency administrator has been appointed in relation to the assets of Repsol.

4.1.13 **Maintenance of capital**: Repsol does not fall into any of the categories set out in articles 363 et seq. of Royal Decree-Law 1/2010 of 2 July, which would require Repsol to be dissolved.

4.1.14 **Winding-up**: no step has been taken to wind-up Repsol nor has any analogous procedure or step been taken in any jurisdiction.

4.1.15 **Essential asset**: the transaction contemplated under the SPA does not fall under the scope of article 160f) of Royal Decree Law 1/2010 of 2 July (essential asset).

4.1.16 **Entry into Agreements**: each signatory of the Relevant Documents has entered into the Relevant Documents in pursuance of a commercial activity and the terms of the Relevant Documents have been freely negotiated by the parties thereto.

4.1.17 **Enforceability of foreign law documents:** the Relevant Documents are valid, binding and enforceable under the laws by which they are expressed to be governed and create valid and legally binding obligations of Repsol under those laws. The execution formalities required under the laws expressed to govern the Relevant Documents for their execution have been complied with.

5. OPINION

5.1 Based on the Documents and on the assumptions referred to above in section 4 and subject to the qualifications set out in section 6 below, we are of the opinion that:

5.1.1 **Status**: Repsol is a public limited liability company (*sociedad anónima*) duly incorporated and validly existing under Spanish law. Repsol has the capacity to sue and to be sued in its corporate name.

5.1.2 **Capacity**: Repsol has the corporate power and capacity to enter into and perform its obligations under the Relevant Documents and the execution, delivery, entry into and performance of its obligations under the Relevant Documents will not contravene its constitutional documents or conflict with or violate Spanish law.

5.1.3 **Authority:** Repsol has taken all necessary corporate actions to authorise the execution, delivery, entry into and performance of its obligations under the Relevant Documents. Accordingly, the Signatory has full power and authority for the execution of the Relevant Documents on behalf of Repsol.

5.1.4 **Due execution:** the Relevant Documents have been duly executed by Repsol.

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5.1.5 **Enforceability:** The Relevant Documents (including the representations and undertakings provided by Repsol under each of those documents) constitute legal, valid and binding obligations of Repsol and as such, are enforceable against Repsol accordingly under Spanish laws.

6. **QUALIFICATIONS**

6.1 This opinion is subject to the qualifications contained in this section:

6.1.1 **Online certificate**: the certificate, excerpt and information referred to in sections 3.1.2, 3.1.3 and 3.1.4, respectively, may not be complete or up-to-date. In particular, it may not be capable of revealing whether or not a winding-up resolution or petition has been presented or administration order made or winding-up resolution or petition for the commencement of insolvency proceedings has been taken or presented to the Commercial Registry or the Public Registry of Insolvency Resolutions since it may take a few weeks before such situations are recorded therein.

6.1.2 **Insolvency, etc.**: if Repsol becomes insolvent, the courts of Spain shall have jurisdiction to open insolvency proceedings. In this case, the law applicable to the insolvency proceedings shall be the Spanish insolvency law. Consequently, the Spanish insolvency law shall determine, *inter alia*, the effects of insolvency proceedings on current contracts to which Repsol is a party, stay of enforcements, etc. In particular, clauses setting out a termination right for the sole cause of the insolvency declaration of the other party would be deemed as non-existent.

6.1.3 **Spanish legal concepts**: Spanish legal concepts are described herein in English terms and such concepts may not be exactly similar to the concepts described by the same English terms. This opinion may, therefore, only be relied upon on the express condition that any issues (e.g. interpretation of Spanish law) arising thereunder will be governed by Spanish law and be brought before a Spanish court.

7. **ADDRESSEE AND RESPONSIBILITY**

7.1 This opinion is given solely for the benefit of Hibiscus and solely in connection with the Proposed Acquisition. It may not be relied upon by (or disclosed to) any other entity or person without our prior written consent, save that this letter may be disclosed without such consent in the following manner:

7.1.1 to the extent required by any order of any court of competent jurisdiction or any competent judicial, governmental, regulatory or supervisory body;

7.1.2 to the extent required by the rules of any listing authority, stock exchange or any regulatory or supervisory body with which you are legally bound to comply;

7.1.3 to your affiliates and the officers, employees, auditors and professional advisers of either you or your affiliates;

7.1.4 that a copy of this opinion letter will be attached to a circular to shareholders of Hibiscus in relation to the Proposed Acquisition, which will be a publicly available document (including on the website of Bursa Malaysia Securities Berhad);

7.1.5 that a copy of this opinion letter may be submitted to Bursa Malaysia Securities Berhad as part of the relevant regulatory approval process in relation to the Proposed Acquisition; and

7.1.6 to the extent required by the laws or regulations of any country with jurisdiction over your affairs,

provided that in each case:

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7.1.7 such disclosure is made for information purposes only and not for the purposes of reliance; and

7.1.8 we do not assume any duty or liability to any person to whom such disclosure is made and no such person to whom this letter is disclosed may rely on it without our prior written consent.

7.2 This opinion is given by Herbert Smith Freehills Spain LLP, which assumes liability for and is solely responsible for it.

Yours faithfully,

Herbert Smith Freehills Spain LLP

LEGAL OPINION ON THE ENFORCEABILITY OF AGREEMENTS, REPRESENTATIONS AND UNDERTAKINGS GIVEN BY THE SELLER UNDER THE LAWS OF ENGLAND AND WALES

HERBERT SMITH FREEHILLS

To: Hibiscus Petroleum Berhad
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Our ref

Your ref

Date
17 November 2021

Dear Sir or Madam,

English law opinion: Sale and purchase agreement between Repsol Exploración, S.A. and Peninsula Hibiscus Sdn Bhd dated 1 June 2021, transition services agreement between Repsol Exploración, S.A. and Peninsula Hibiscus Sdn Bhd dated 11 November 2021, and parent company guarantee between Hibiscus Petroleum Berhad and Repsol Exploración, S.A. dated 1 June 2021

1. AGREEMENTS REFERRED TO IN THIS OPINION

1.1 We have been asked to provide an English law legal opinion to Hibiscus Petroleum Berhad ("**Hibiscus**") in connection with an English law governed sale and purchase agreement dated 1 June 2021 (the "**SPA**") made between Repsol Exploración, S.A., as seller (the "**Seller**") and Peninsula Hibiscus Sdn Bhd, as purchaser (the "**Purchaser**") for the proposed acquisition by the Purchaser of the entire equity interest in Fortuna International Petroleum Corporation (the "**Company**") from the Seller ("**Proposed Acquisition**"), an English law governed transition services agreement dated 11 November 2021 (the "**Transition Services Agreement**") between the Seller and the Purchaser, and an English law governed parent company guarantee dated 1 June 2021 (the "**Parent Company Guarantee**") between Hibiscus, as guarantor, and the Seller, as beneficiary, each as more particularly described in the circular distributed to the shareholders of Hibiscus in relation to the Proposed Acquisition, to which a copy of this letter will be attached.

1.2 In this opinion, save as otherwise specified or as the context may otherwise require, expressions defined in the SPA, as at the date of this letter, shall have the same meanings when used in this opinion.

2. SCOPE OF THIS OPINION

2.1 We are solicitors qualified in England and Wales. We express no opinion as to any law other than English law as applied by English courts and reported and in effect on the date of this opinion.

2.2 No opinion is expressed as to matters of fact.

2.3 We have advised Hibiscus in respect of certain matters of English law in respect of the SPA and the Parent Company Guarantee. We have not received instructions from any of the parties to the Transition Services Agreement in connection with the Transition Services Agreement nor advised any of the parties in connection with the Transition Services Agreement. In particular, but without affecting the generality of the foregoing sentence, we have not advised any of the parties on the type, adequacy, nature and appropriateness of the interests, rights, obligations or remedies which may arise under the Transition Services Agreement.

2.4 This opinion and any non-contractual obligations arising out of or in connection with it are governed by and shall be construed in accordance with English law. This opinion is given on condition that the courts of England have exclusive jurisdiction to settle any dispute or claim arising out of or in connection herewith (including any non-contractual disputes or claims).

2.5 This opinion is not designed to and is not likely to reveal fraud, misrepresentation, bribery or corruption by any person.

3. DOCUMENTS WHICH WE HAVE EXAMINED AND ENQUIRIES WHICH WE HAVE MADE

3.1 We have examined the following documents for the purposes of giving this opinion:

3.1.1 a scanned version of the signed SPA dated 1 June 2021;

3.1.2 a scanned version of the signed Transition Services Agreement dated 11 November 2021; and

3.1.3 a scanned version of the signed Parent Company Guarantee dated 1 June 2021.

3.2 In this opinion, each of the SPA, the Transition Services Agreement and the Parent Company Guarantee shall be individually referred to as an "**Agreement**" and shall together be referred to as the "**Agreements**".

3.3 Except as stated above, we have not for the purpose of this opinion examined any agreements, documents or corporate records entered into by or affecting the parties to the Agreements ("**Parties**") or made any other enquiries concerning the Parties.

4. ASSUMPTIONS

4.1 This opinion is based upon the assumption (which may or may not be the case) that:

4.1.1 **Due incorporation:** each Party is a company duly incorporated under its law of incorporation;

4.1.2 **Authenticity:** all documents (including scanned, electronic and copy documents) examined by us (as set out in paragraph 3 above) are authentic, complete and accurate and all signatures and seals (if any) thereon are genuine;

4.1.3 **Documents up-to-date etc.:** all documents which we have examined (as set out in paragraph 3 above) are and remain up-to-date, and have not been amended, superseded, terminated or rescinded;

4.1.4 **Parties – capacity and authority etc.:** each Party to an Agreement has the power and legal capacity to enter into, perform and exercise its rights under each of the Agreements to which it is a party and each of the Agreements has been duly authorised, executed and, where applicable, delivered by all of the Parties thereto in accordance with all applicable laws;

4.1.5 **Solvency:** each Party was solvent at the time of the execution and delivery of the Agreements and did not become insolvent as a result of entering into the arrangements contained in the Agreements and no Party has entered into any composition or arrangement with its creditors (or any class of them);

4.1.6 **Administration etc.:** no step has been taken to obtain a moratorium in relation to any Party or to wind up any Party or to place any Party into administration and that no receiver has been appointed over or in respect of the assets of any Party, nor has any analogous procedure or step been taken in any jurisdiction;

4.1.7 **Overseas insolvency:** no foreign main insolvency proceeding has been recognised in Great Britain under the Cross-Border Insolvency Regulations 2006 (and it is not possible to conduct a central search in Great Britain in relation to any such proceedings) which would entitle actions in respect of any assets of any Party the subject of those foreign proceedings to be taken in Great Britain;

4.1.8 **Validity/enforceable obligations:** the Agreements constitute legal, valid, binding and enforceable obligations of all of the parties thereto under all applicable laws (other than English law) and to the extent that the laws or regulations of any jurisdiction other than England may be relevant to (i) the obligations or rights of any of the parties under the Agreements, or (ii) any of the transactions contemplated by the Agreements, such laws and regulations do not prohibit, and are not inconsistent with, the entering into and performance of any such obligations, rights or transactions;

4.1.9 **No breach:** no Party will, by reason of the transactions contemplated by the Agreements, be in breach of any of their respective obligations under any agreement, licence, authorisation, consent or similar document;

4.1.10 **Misconduct etc.:** no party to an Agreement (and no individual employed by or acting on behalf of any such party) is, or will be, engaging in criminal, misleading, deceptive or unconscionable conduct or seeking to conduct any relevant transaction or any associated activity in a manner or for a purpose not evident on the face of the Agreement which might render the Agreement (or any part thereof) or any transaction contemplated thereby or any associated activity illegal, unlawful, void or unenforceable;

4.1.11 **Entry into Agreements:** each Party has entered into the Agreements (to which it is a party) in pursuance of a commercial activity and the terms of the Agreements have been freely negotiated by the parties thereto;

4.1.12 **Entry into Agreements outside the UK:** the Agreements were executed outside the United Kingdom and do not relate to any things done or to be done in the United Kingdom, or to any property situated in the United Kingdom; and

4.1.13 **No UK Share Register etc:** None of the shares in the Company is (i) registered on a register kept by or on behalf of the Company in the United Kingdom, or (ii) paired with shares of a body corporate incorporated in the United Kingdom.

5. OPINION

5.1 Based on the Agreements and subject to the assumptions contained in paragraph 4 and the qualifications contained in paragraph 6 and to matters not disclosed to us, it is our opinion that:

5.1.1 **Validity:** the obligations of the Seller under each Agreement constitute legal, valid, binding and enforceable obligations of the Seller;

5.1.2 **Consents:** except as may be detailed within each Agreement, no authorisations or consents of governmental, judicial or other public bodies in England or Wales are required by any Party for the purposes of ensuring the validity, binding effect or enforceability of the obligations of the Seller under any Agreement;

5.1.3 **Registration:** it is not necessary to file, register or record any Agreement in any register maintained by any public or statutory body in England or Wales for the purposes of ensuring the validity, binding effect or enforceability of the obligations of the Seller under any Agreement; and

5.1.4 **Stamp duty:** no stamp, registration or similar duties are payable in England or Wales in respect of the execution and delivery of the Agreements.

6. QUALIFICATIONS

6.1 This opinion is subject to the qualifications contained in this section.

6.2 **Insolvency etc.:** This opinion is subject to all insolvency and other laws affecting the rights of creditors (whether secured or unsecured) generally.

6.3 **Validity:** The opinion that the obligations of the Seller under the Agreements constitute legal, valid, binding and enforceable obligations means that the obligations are of a type and form generally found to be legal, valid, binding and enforceable by the English courts or arbitral tribunals applying English law. It is not, however, certain that those obligations will necessarily be legal, valid or binding or will be enforced in all circumstances in accordance with their terms, since the existence, effect and enforcement of legal obligations is subject to principles of law, equity, court or the arbitral tribunal's discretion, issues of public policy and procedure of general application. Nor is it the case that English law will apply in all circumstances nor that an English court or arbitral tribunal will have jurisdiction in all circumstances. In particular:

6.3.1 equitable remedies, such as specific performance and injunctions, are within the discretion of the court or arbitral tribunal, and may be subject to the power to award such remedies being available to the arbitral tribunal. An English court or arbitral tribunal may make an award of damages if it considers this an adequate remedy for breach of legal obligations and not grant an equitable remedy in such circumstances;

6.3.2 claims may become time-barred;

6.3.3 enforcement of rights and obligations may become frustrated;

6.3.4 claims may be subject to defences of set-off or counterclaim;

6.3.5 a failure or delay to exercise a right may constitute a waiver of that right;

6.3.6 any indemnity obligations imposed under any of the Agreements may not be effective insofar as they relate to fines and penalties arising out of matters of civil or criminal liability and an indemnity for costs of litigation may not be effective;

6.3.7 an agreement whereby a party is to pay the whole or part of the costs of the arbitration in any event may not be valid if made before the dispute in question has arisen;

6.3.8 any terms excluding or limiting the duties owed by or the liability of any person may be void if and to the extent they do not satisfy the relevant tests of reasonableness or fairness imposed by law and will be construed strictly;

6.3.9 an obligation to negotiate or enter into further agreements may not be enforceable;

6.3.10 an English court or arbitral tribunal may choose not to treat any certificate or determination as being conclusive;

6.3.11 the severance of any invalid or illegal provision and the continued effect of any other obligations will be determined by an English court or arbitral tribunal, at its discretion;

6.3.12 any discretion or determination may be required to be exercised or made in a timely manner, reasonably or in good faith, and not arbitrarily, capriciously, perversely or irrationally, whether or not there is any express obligation to do so;

6.3.13 any provision in a contract which requires payment of additional amounts by any party as a result of breach of its contractual obligations (whether expressed by way of fee, additional interest (whether described as penalty or default interest or implemented by margin ratchet), or specified or liquidated damages or otherwise), or which results in the loss of a right to a future payment or a requirement to transfer assets at an undervalue, may be unenforceable as a penalty;

6.3.14 notwithstanding any contractual provision that requires a variation to be made in writing or to comply with some other formality, a party may in some circumstances be prevented from enforcing the original terms where a variation was agreed orally or by conduct of the parties;

6.3.15 a contract may not be binding if the consideration given for the benefit of a promise is not valuable consideration or is past consideration;

6.3.16 if a provision lacks certainty it may not be contractually binding;

6.3.17 an English court or any arbitral tribunal applying English law may choose not to enforce or recognise as binding obligations which are incompatible with English public policy or which purport to override mandatory rules of English law;

6.3.18 an arbitral tribunal may choose not to enforce or recognise as binding an agreement if it creates obligations which are incompatible with the public policy of the arbitral seat or where it purports to override mandatory rules of the seat;

6.3.19 any right to apply payments in a specific order may not be effective if a Party, in making payment, specifies a contrary order of application;

6.3.20 an indemnity in respect of or other undertaking or other arrangements to pay United Kingdom stamp duty may be void by virtue of section 117 of the Stamp Act 1891;

6.3.21 a contract may be void if the parties are mistaken as to some matter that is essential to the contract; and

6.3.22 by virtue of section 233B of the Insolvency Act 1986, a provision of a contract for the supply of goods or services to a company ceases to have effect when the company becomes subject to a relevant insolvency procedure if and to the extent that, under the provision (a) the contract or the supply would terminate, or any other thing would take place, because the company becomes subject to the relevant insolvency procedure, or (b) the supplier would be entitled to terminate the contract or the supply, or to do any other thing, because the company becomes subject to the relevant insolvency procedure.

6.4 **Unlawful communications:** An agreement which is entered into in consequence of an unlawful communication may be unenforceable pursuant to the Financial Services and Markets Act 2000.

6.5 **Tax:** Apart from the statements contained in paragraph 5.1.4, we express no opinion on any tax matters. We express no opinion as to the tax treatment of the Agreements or the transactions contemplated thereby.

6.6 **Choice of law - arbitral tribunal seated outside England:** We express no opinion as to the circumstances in which an arbitral tribunal seated outside England might refuse to apply the chosen law because this will be governed by the law of the seat.

6.7 **Recognition of arbitration by the English courts:** the submission of disputes to arbitration will be recognised by the English courts subject to the exceptions and provisions of the Arbitration Act 1996, other relevant principles of English law, and any other mandatory statute, including applicable EU law.

6.8 **Sanctions:**

6.8.1 Where a party to the Agreements is the subject of targeted financial sanctions or restrictive measures implemented or effective in England and Wales, or is owned or controlled (directly or indirectly) by, or is acting on behalf of, a person subject to such sanctions (a **"Sanctioned Person"**), then the obligations and rights of the parties under the Agreements may be unenforceable or void. Where the performance of any obligations under the Agreements would otherwise involve the provision of any funds or assets (directly or indirectly) to a Sanctioned Person or a use of or dealing with funds or assets belonging to, or owned, held or controlled by, a Sanctioned Person, then such obligations may be unenforceable or void. Where any Party is the subject of other restrictive measures (including trade sanctions or embargoes, financing restrictions and investment restrictions) implemented or effective in England and Wales which affect the provision of finance or credit to, or payments to or from, such persons (as a result of being resident in, incorporated in or constituted under the laws of a country which is subject to such measures, or being part of a class of persons of a generic description subject to such measures, or being named as subject to such measures), or where the proceeds of any loan made available under any Agreement are to be used for activities which are contrary to such measures, then the obligations and rights of the Parties under the Agreements may be unenforceable or void.

6.8.2 We express no opinion on the legality or enforceability of clause 6.5 of the SPA, paragraph 14 of Schedule 4 of the SPA and paragraphs 4 and 5 of Schedule 6 of the SPA or any other representation or undertaking relating to sanctions or the use of proceeds or whether they violate English law to the extent they have an effect of contravening EU Council Regulation (EC) No. 2271/96 (to the extent applicable), and/or its equivalent in retained EU law (including having regard to (the retained EU law equivalent of) Commission Implementing Regulation (EU) 2018/1101, the Extraterritorial US Legislation (Sanctions against Cuba, Iran and Libya) Protection of Trading Interests Order 1996 and the Protecting against the

HERBERT SMITH FREEHILLS

Date
17 November 2021
Letter to
Hibiscus Petroleum Berhad

Effects of the Extraterritorial Application of Third Country Legislation) (Amendment) (EU Exit) Regulations 2020).

6.9 **Consents:** No opinion is given in relation to the need for any authorisations or consents in connection with the performance of any Agreement (including the undertaking of any transaction, or the doing of any other thing, under any Agreement).

7. **ADDRESSEES AND RESPONSIBILITY**

7.1 This opinion is given solely for the benefit of Hibiscus and solely in connection with the Proposed Acquisition. It may not be relied upon by (or disclosed to) any other entity or person without our prior written consent, save that this letter may be disclosed without such consent in the following manner:

7.1.1 to the extent required by any order of any court of competent jurisdiction or any competent judicial, governmental, regulatory or supervisory body;

7.1.2 to the extent required by the rules of any listing authority, stock exchange or any regulatory or supervisory body with which you are legally bound to comply;

7.1.3 to your affiliates and the officers, employees, auditors and professional advisers of either you or your affiliates;

7.1.4 a copy of this opinion letter will be attached to a circular to shareholders of Hibiscus in relation to the Proposed Acquisition, which will be a publicly available document (including on the website of Bursa Malaysia Securities Berhad);

7.1.5 a copy of this opinion letter may be submitted to Bursa Malaysia Securities Berhad as part of the relevant regulatory approval process in relation to the Proposed Acquisition; and

7.1.6 to the extent required by the laws or regulations of any country with jurisdiction over your affairs,

provided that in each case:

(A) such disclosure is made for information purposes only and not for the purposes of reliance; and

(B) we do not assume any duty or liability to any person to whom such disclosure is made and no such person to whom this letter is disclosed may rely on it without our prior written consent.

7.2 This opinion is given by Herbert Smith Freehills LLP, which assumes liability for and is solely responsible for it.

Yours faithfully,

Herbert Smith Freehills

Herbert Smith Freehills LLP

FORTUNA INTERNATIONAL PETROLEUM CORPORATION

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Tel: (246) 436-9929 Fax: (246) 436-9932

Registered Office:
1st Floor, Limegrove Centre
Holetown, St. James
Barbados BB24016

Date: 10 December 2021

The Board of Directors
Hibiscus Petroleum Berhad
12th Floor, Menara Symphony
No. 5, Jalan Prof. Khoo Kay Kim
Seksyen 13
46200 Petaling Jaya
Selangor Darul Ehsan
Malaysia

Dear Sir/Madam,

On behalf of the Board of Directors of Fortuna International Petroleum Corporation ("**FIPC**"), we wish to report that, after due inquiries in relation to FIPC and its subsidiaries ("**FIPC Group**") during the period from 31 December 2020 (being the date to which the last audited financial statements of FIPC and its subsidiaries, namely Repsol Oil & Gas Malaysia Limited ("**RML**"), Repsol Oil & Gas Malaysia (PM3) Limited ("**RMPM3**") and Talisman Vietnam Limited ("**TVL**") have been made up) to the date herein (being a date not earlier than 14 days before the issue of this Circular) that, to the best of our knowledge and belief:

(i) the business of the FIPC Group has been conducted to the extent within the reasonable control of the Board of Directors: (a) in the ordinary course of business; (b) in accordance with good oil and gas field practice; (c) in accordance with applicable law; and (d) in substantially the same manner as prior to the date of the sale and purchase agreement for the proposed acquisition by Peninsula Hibiscus Sdn Bhd, an indirect wholly-owned subsidiary of Hibiscus Petroleum Berhad, of the entire equity interest in FIPC ("**Proposed Acquisition**") ("**SPA**");

(ii) no circumstances have arisen since the last audited financial statements of FIPC and its subsidiaries, RML, RMPM3 and TVL, which have adversely affected the trading or the value of the assets of the FIPC Group resulting in a reduction in the value of FIPC or any of its subsidiaries by an amount equal to or exceeding thirty per cent (30%) of USD212.5 million ("**Purchase Price**");

(iii) there are no contingent liabilities by reason of any guarantee or indemnity given by the FIPC Group to secure a financial or other obligation in respect of another person's obligation;

(iv) there has been no default or any known event that could give rise to a default situation, on payments of either interest and/or principal sums in relation to any borrowings in which they are aware of, since the last audited financial statements of FIPC and its subsidiaries, RML, RMPM3 and TVL; and

(v) since the last audited financial statements of FIPC and its subsidiaries, RML, RMPM3 and TVL, there has been no event or circumstance occurring which:

(a) has resulted in physical loss of, or damage or destruction to, assets or facilities owned or leased by the FIPC Group for the conduct of its operations; and

(b) has had, or is reasonably likely to have, a material adverse effect on the financial condition, assets, liabilities, operations, profitability or prospects of the FIPC Group or its operations resulting in a reduction in the value of FIPC or any of its subsidiaries by an amount equal to or exceeding thirty per cent (30%) of the Purchase Price.

This Directors' Report is addressed solely to Hibiscus Petroleum Berhad for the purpose of inclusion in a circular to its shareholders in connection with the Proposed Acquisition and may not in any circumstances be relied upon by any other persons or for any other purpose whatsoever and the Directors of FIPC shall not be liable or responsible for any loss or damage of such other persons arising out of, in connection with or relating to this Directors' Report.

The above matters are subject to the qualifications and limitations to any claims against the Seller set out in the SPA.

Yours faithfully
For and on behalf of the Board of Directors of
Fortuna International Petroleum Corporation

Sir Trevor Carmichael
Director

The Board of Directors
Hibiscus Petroleum Berhad
2nd floor,
Syed Kechik Foundation Building,
Jalan Kapas, Bangsar,
59100 Kuala Lumpur.

4 October 2021

PwC/TEH/NNH/sw/0895B1

Dear Sirs,

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Fortuna International Petroleum Corporation

Our Opinion

We have audited the accompanying financial statements of Fortuna International Petroleum Corporation ("FIPC" or the "Target Company") which comprise the statements of financial position as at 31 December 2018, 31 December 2019 and 31 December 2020, the statements of profit or loss and other comprehensive income, statements of changes in shareholder's equity and statements of cash flows for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, and a summary of significant accounting policies and other explanatory notes (together, the "Financial Statements"), as set out on pages 1 to 23. The Financial Statements have been prepared for purposes of inclusion in Hibiscus Petroleum Berhad ("HPB")'s circular to shareholders of HPB (the "Circular to Shareholders") in connection with the proposed acquisition of Fortuna International Petroleum Corporation and its subsidiaries by HPB (the "Proposal").

In our opinion, the Financial Statements give a true and fair view of the financial position of the Target Company as at 31 December 2018, 31 December 2019 and 31 December 2020 and of its financial performance and cash flows for each of the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS").

PricewaterhouseCoopers PLT (LLP0014401-LCA & AF 1146), Chartered Accountants, Level 10, 1 Sentral, Jalan Rakyat, Kuala Lumpur Sentral, P.O. Box 10192, 50706 Kuala Lumpur, Malaysia
T: +60 (3) 2173 1188, F: +60 (3) 2173 1288, www.pwc.com/my

pwc

The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0895B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Fortuna International Petroleum Corporation (Continued)

Basis for Opinion

We conducted our audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing. Our responsibilities under those standards are further described in the Reporting Accountant's Responsibilities for the Audit of the Financial Statements section of our report. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence and Other Ethical Responsibilities
We are independent of the Target Company in accordance with the By-Laws (on Professional Ethics, Conduct and Practice) of the Malaysian Institute of Accountants ("By-Laws") and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) ("IESBA Code"), and we have fulfilled our other ethical responsibilities in accordance with the By-Laws and the IESBA Code.

Emphasis of Matter

We draw attention to Note 2 to the Financial Statements, which disclosed that the consolidated financial statements of FIPC and its subsidiaries have not been prepared for inclusion in the Circular to Shareholders of HPB as the Target Company has applied the exemption from preparing consolidated financial statements in accordance with MFRS 10/IFRS 10 "Consolidated Financial Statements". The Target Company is a wholly-owned subsidiary of Repsol, S.A., a Spain-incorporated company which produces consolidated financial statements available for public use that comply with IFRS. Our opinion is not modified in respect of this matter.

Directors' Responsibilities for the Financial Statements

The Directors of the Target Company are responsible for the preparation of the Financial Statements for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020 that gives a true and fair view in accordance with the MFRS and IFRS. The Directors of the Target Company are also responsible for such internal control as the Directors of the Target Company determine is necessary to enable the preparation of the Financial Statements that is free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements of the Target Company, the Directors of the Target Company are responsible for assessing the Target Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors of the Target Company either intend to liquidate the Target Company or to cease operations, or have no realistic alternative but to do so.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0895B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Fortuna International Petroleum Corporation (Continued)

Reporting Accountant's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements of the Target Company as a whole are free from material misstatement, whether due to fraud or error, and to issue a report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with approved standards on auditing in Malaysia and International Standards on Auditing will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

As part of an audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Financial Statements of the Target Company, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Target Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors of the Target Company.
- Conclude on the appropriateness of the Directors of the Target Company's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Target Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our report to the related disclosures in the Financial Statements of the Target Company or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our report. However, future events or conditions may cause the Target Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the Financial Statements of the Target Company, including the disclosures, and whether the Financial Statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Directors of the Target Company regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0895B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Fortuna International Petroleum Corporation (Continued)

Restriction on Distribution and Use

This report is issued for the sole purpose of inclusion in the Circular to Shareholders of HPB in connection with the Proposal, and should not be relied on for any other purposes. Accordingly, we will not accept any liability or responsibility to any other party to whom our report is shown or into whose hands it may come.

Yours faithfully,

PricewaterhouseCoopers PLT

PRICEWATERHOUSECOOPERS PLT
LLP0014401-LCA & AF 1146
Chartered Accountant

FORTUNA INTERNATIONAL PETROLEUM CORPORATION

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 and 31.12.2018

Fortuna International Petroleum Corporation

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

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Fortuna International Petroleum Corporation
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Fortuna International Petroleum Corporation

STATEMENTS OF FINANCIAL POSITIONS

(U.S. dollars)	Note	USD'000 As at 31.12.2020	USD'000 As at 31.12.2019	USD'000 As at 31.12.2018
Assets				
Investments in subsidiaries	8	181,074	181,074	181,074
Deferred tax assets	11	-	1,211	1,329
Non-current Assets		**181,074**	**182,285**	**182,403**
Prepayment and other receivables		28	28	26
Income tax receivable	11	665	683	683
Loans to related parties	9, 14	473	354,702	346,774
Cash and cash equivalents		12	18	72
Current Assets		**1,178**	**355,431**	**347,555**
Total Assets		**182,252**	**537,716**	**529,958**
Shareholder's Equity and Liabilities				
Share capital	9, 10	182,094	452,322	452,322
Retained earnings		133	85,374	77,611
Shareholder's Equity		**182,227**	**537,696**	**529,933**
Due to related parties	14	-	-	7
Trade and account payables		25	20	18
Current Liabilities		**25**	**20**	**25**
Total Shareholder's Equity and Liabilities		**182,252**	**537,716**	**529,958**

Notes 1 to 16 are an integral part of the financial statements.

Approved by Khoo Pooi Yin on behalf of the Directors on October 4, 2021:

Page 1

Fortuna International Petroleum Corporation

STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
FOR THE YEARS ENDED

(U.S. dollars)	Note	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Interest Income		2,931	7,928	7,422
Dividend income		10,000	-	3
Revenue	12	**12,931**	**7,928**	**7,425**
General and administrative		(54)	(47)	(105)
Results from operating activities		**12,877**	**7,881**	**7,320**
Profit before income tax		**12,877**	**7,881**	**7,320**
Income tax expense	11	(1,346)	(118)	3,351
Profit for the period		**11,531**	**7,763**	**10,671**
Total comprehensive income for the period		**11,531**	**7,763**	**10,671**

Notes 1 to 16 are an integral part of the financial statements.

Fortuna International Petroleum Corporation

STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
FOR THE YEARS ENDED

	Share Capital	Retained Earnings	Total
At 01.01.2018	**456,273**	**66,940**	**523,213**
Return of capital (note 10)	(190,000)	-	(190,000)
Addition of capital (note 10)	186,049	-	186,049
Total recognised income and expense	-	10,671	10,671
At 31.12.2018/01.01.2019	**452,322**	**77,611**	**529,933**
Total recognised income and expense	-	7,763	7,763
At 31.12.2019/01.01.2020	**452,322**	**85,374**	**537,696**
Return of capital	(270,228)	-	(270,228)
Dividends paid	-	(96,772)	(96,772)
Total recognised income and expense	-	11,531	11,531
At 31.12.2020	**182,094**	**133**	**182,227**

Notes 1 to 16 are an integral part of the financial statements.

Fortuna International Petroleum Corporation
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Fortuna International Petroleum Corporation

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED

(U.S. dollars)	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Cash flows from operating activities			
Profit for the period before tax	12,877	7,881	7,320
Adjustment for:			
Dividend income	(10,000)	-	-
Interest income	(2,931)	(7,928)	(7,422)
Changes in operating assets and liabilities			
Prepayment and other receivables	-	(2)	(542)
Accounts payable	5	(5)	(19,885)
Other current liabilities	-	-	251
Tax paid	(117)	-	-
Cash flows from operating activities	**(166)**	**(54)**	**(20,278)**
Cash flows from Investing Activities			
Repayment of loan from related parties	160	-	209,903
Cash flows used in Investing Activities	**160**		**209,903**
Cash flows from Financing Activities			
Repayment of share capital	-	-	(190,000)
Cash flows used in Financing Activities	-	-	**(190,000)**
Net decrease in cash and cash equivalents	**(6)**	**(54)**	**(375)**
Cash and cash equivalents, beginning of year	18	72	447
Cash and cash equivalents, end of year	**12**	**18**	**72**

Non-cash activity – return of capital, transfer of redeemable preference shares to capital, dividends paid and loan repayment (note 9 and 10).

Notes 1 to 16 are an integral part of the financial statements.

Fortuna International Petroleum Corporation

Notes to the financial statements
For the years ended 31.12.2020, 31.12.2019, 31.12.2018

1. GENERAL INFORMATION

This Accountants' Report contains the financial statements of Fortuna International Petroleum Corporation (hereinafter, "the Company") which comprise the statements of financial position as at December 31, 2020, December 31, 2019 and December 31, 2018, the statements of profit or loss and other comprehensive income, statements of changes in Shareholder's equity and statements of cash flows for the financial years ended December 31, 2020, December 31, 2019 and December 31, 2018, and a summary of significant accounting policies and other explanatory notes. The financial statements were prepared by management and approved by the Directors of the Company.

The Company was incorporated on November 21, 2001 under the Barbados Companies Act Cap 308 (the "Act"). The principal activity of the Company is investment holding. The Company was licensed and operates under the International Business Companies Act.

Effective January 1, 2019, the International Business Companies Act Cap. 77 was repealed, and all companies licensed under this act prior to its repeal, are now licensed under the Companies Act Cap. 308. Existing licensees will have until 2021 to transition into the regime and will have the benefit of grandfathering provisions until they do so under the International Business Companies (Repealed) Act 2018-40. In conjunction with the repeal of the International Business Companies Act Cap. 77, the Income Tax Act Cap. 73 was also amended. The amended Income Tax Act Cap. 73 applies new effective and staggered rates of tax from 1.0% to 5.5% based on a Company's taxable income. The Company elected to be grandfathered in accordance with International Business Companies (Repeal) Act, 2018-40 of Barbados until June 30, 2021. As a result the tax rates remain at 1.0% to 2.5%.

The Company is a wholly owned subsidiary of Repsol Exploración S.A., immediate parent of the company, and Repsol, S.A. is the ultimate parent of the Company.

The registered office of the Company is 1st Floor, Limegrove Centre, Holetown, St. James, Barbados.

Repsol Exploración, S.A. is registered at the Madrid Companies Register and its registered office is in Madrid, 44 Méndez Álvaro Street.

The Company is part of a group of companies under the terms of article 42 of the Code of Commerce, Repsol Group, whose ultimate parent company is Repsol, S.A. Repsol, S.A. is registered at the Madrid Companies Register in sheet no. M-65289. Its registered office is in Madrid, 44 Méndez Álvaro Street.

The annual accounts of the Company are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The functional currency of the Company is United States Dollar ("USD").

2. BASIS OF PREPARATION OF THE FINANCIAL STATEMENTS

The financial statements of the Company for the year ended December 31, 2020, December 31, 2019 and December 31, 2018 have been prepared in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS") and which include the Statement of financial position, Statement of Profit and Loss and Other Comprehensive income, Statement of Changes in Shareholder's equity, Statement of Cash Flows and Notes.

The preparation of financial statements in conformity with MFRS/IFRS requires the use of certain critical accounting estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reported period. It also requires the directors to exercise their judgment in the process of applying the Company's accounting policies. Although these estimates and judgment are based on the Directors' best knowledge of current events and actions, actual results may differ. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4 to the financial statements.

These financial statements are the separate financial statements of Fortuna International Petroleum Corporation. The Company is exempted from the preparation of consolidated financial statements in accordance with MFRS 10/IFRS 10 'Consolidated Financial Statements' as the Company is a wholly-owned subsidiary of Repsol, S.A., a Spain-incorporated company which produces consolidated financial statements available for public use that comply with International Financial Reporting Standards. The address where the consolidated financial statements are obtainable is as follows: https://www.repsol.com/en/shareholders-and-investors/financial-information/annual-reports/index.cshtml.
The information of the subsidiaries of the Company including their names, principal place of business and proportion of ownership of each subsidiary are disclosed in Note 8. Should the consolidated financial statements of FIPC and its subsidiaries ("FIPC Group") be prepared, the following material adjustments will be made in the consolidated financial statements of FIPC Group:
- intercompany transactions and balances within FIPC Group will be eliminated;
- the carrying amounts of the assets and liabilities of Talisman Vietnam Limited ("TVL"), Repsol Oil & Gas Malaysia Limited ("RML") and Repsol Oil & Gas Malaysia (PM3) Limited ("RMP" or "RMPM3") would have been measured at their respective fair values at dates of acquisition by FIPC; and
- the excess of the purchase consideration and fair values of assets and liabilities of TVL, RML and RMP at their respective dates of acquisition by FIPC will be recognised as goodwill.

2.1 Amendments to published standards that are effective

Effective for annual period beginning on/after January 1, 2018

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2018:

- MFRS 9/ IFRS 9 'Financial Instruments'
- MFRS 15/IFRS 15 'Revenue from Contracts with Customers'
- IFRIC 22 'Foreign Currency Transactions and Advance Consideration'

The Company has adopted MFRS 9/IFRS 9 for the first time in the 2018 financial year, which resulted in changes in accounting policies. The Company accounting policies on financial instruments are disclosed in details in Notes 3.5 and 3.6. The impact from the adoption of these standards is not material to the Company.

Effective for annual period beginning on/after January 1, 2019

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2019:

- MFRS 16/IFRS 16 'Leases'
- Amendments to MFRS 9/IFRS 9 'Prepayment Features with Negative Compensation'
- Amendments to MFRS 119/IAS 19 'Plan Amendment, Curtailment or Settlement'
- IFRIC 23 'Uncertainty over Income Tax Treatments'
- Annual Improvements to MFRSs/IFRSs 2015 - 2017 Cycle

The adoption of amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

Effective for annual period beginning on/after January 1, 2020

The Company has applied the following amendments to the standards for the first time for the financial year beginning on January 1, 2020:

- The Conceptual Framework for Financial Reporting (Revised 2018)
- Amendments to MFRS 101/IAS 1 and MFRS 108/IAS 8 'Definition of Material'
- Amendments to MFRS 9/IFRS 9, MFRS 139/IAS 39 and MFRS 7/IFRS 7 'Interest Rate Benchmark Reform'

The adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

2.2 Amendments to published standards that have been issued but not yet effective

Effective for annual period beginning on/after June 1, 2020

- In May 2020, the IASB issued COVID-19-Related Rent Concessions (Amendment to MFRS 16/IFRS 16) that grant an optional exemption for lessees to account for rent concessions occurring as a direct consequence of COVID-19.

  Such concessions might take a variety of forms, including payment holidays and deferral of lease payments. In many cases, this will result in accounting for the concession as a variable lease payment in the period(s) in which the event or condition that triggers the reduced payment occurs.

  The optional exemption permits a lessee to elect not to assess whether a COVID-19-related rent concession is a lease modification. A lessee that makes this election shall account for any change in lease payments resulting from the COVID-19-related rent concession the same way it would account for the change applying MFRS 16/IFRS 16 if the change were not a lease modification.

  The practical expedient applies only to rent concessions occurring as a direct consequence of COVID-19 and only if all of the following conditions are met:
  - The change in lease payments results in revised consideration for the lease that is substantially the same as, or less than, the consideration for the lease immediately preceding the change;
  - Any reduction in lease payments affects only payments originally due on or before June 30, 2021 (a rent concession meets this condition if it results in reduced lease payments on or before June 30, 2021 and increased lease payments that extend beyond June 30, 2021); and
  - There is no substantive change to other terms and conditions of the lease.

  The amendments shall be applied retrospectively.

The impact from the adoption of these standards is not material to the Company.

Effective for annual period beginning on/after January 1, 2022

- The amendments to MFRS 116/IAS 16 'Property, Plant and Equipment - Proceeds before Intended Use' prohibit an entity deducting from the cost of an item of property, plant and equipment the proceeds received from selling items produced by the property, plant and equipment before that asset is ready for its intended use, i.e. proceeds while bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Consequently, an entity recognises such sales proceeds and related costs in profit or loss.

  The amendments also clarify the meaning of 'testing whether an asset is functioning properly'. MFRS 116/IAS 16 now specifies this as assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes.

  If not presented separately in the statement of comprehensive income, the financial statements shall disclose the amounts of proceeds and cost included in profit or loss that relate to items produced that are not an output of the entity's ordinary activities, and which line item(s) in the statement of comprehensive income include(s) such proceeds and cost.

  The amendments are applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments.

The entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the beginning of that earliest period presented.

- The amendments to MFRS 137/IAS 37 'Onerous Contracts – Cost of Fulfilling a Contract' specify that the 'cost of fulfilling' a contract comprises the 'costs that relate directly to the contract'. Costs that relate directly to a contract consist of both the incremental costs of fulfilling that contract, as well as an allocation of other costs that relate directly to fulfilling contracts. The amendments also clarify that before recognising a separate provision for an onerous contract, impairment loss that has occurred on assets used in fulfilling the contract should be recognised.

  The amendments shall be applied retrospectively and apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments. Comparatives are not restated.

  Instead, the entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings or other component of equity, as appropriate, at the date of initial application.

- Annual Improvements to MFRS/IFRS Standards 2018–2020 (Effective date 1 January 2022)

  - The following improvements were finalised in May 2020:
  - MFRS 9/IFRS 9 Financial Instruments – clarifies which fees should be included in the 10% test for derecognition of financial liabilities.
  - MFRS 16/IFRS 16 Leases – amendment of illustrative example 13 to remove the illustration of payments from the lessor relating to leasehold improvements, to remove any confusion about the treatment of lease incentives.
  - MFRS 1/IFRS 1 First-time Adoption of International Financial Reporting Standards – allows entities that have measured their assets and liabilities at carrying amounts recorded in their parent's books to also measure any cumulative translation differences using the amounts reported by the parent. This amendment will also apply to associates and joint ventures that have taken the same MFRS 1/IFRS 1 exemption.

The impact from the adoption of these standards is not material to the Company.

Effective for annual period beginning on/after January 1, 2023

- Amendments to MFRS 101/IAS 1 - Disclosure of accounting policy information - require entities to disclose their material rather than their significant accounting policies. (Effective date 1 January 2023).

- Amendments to MFRS 108/IAS 8 - Definition of accounting estimates - clarifies how companies should distinguish changes in accounting policies from changes in accounting estimates (Effective date 1 January 2023).

- The amendments to MFRS 101/IAS 1 'Classification of Liabilities as Current or Non-current' affect only the presentation of liabilities as current or non-current in the statement of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items (Effective date 1 January 2023).

  The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants are complied with at the end of the reporting period, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

3.1 Basis of accounting

The financial statements of the Company have been prepared under the historical cost convention unless otherwise stated in the accounting policies mentioned below. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

3.2 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Company takes into account the characteristics of the asset or liability if market participants would take those characteristic into account when pricing the asset or a liability at the measurement date. Fair value for measurement and/or disclosure purposes in these financial statements is determined on such a basis, except for any share-based payment transactions that are within the scope of MFRS 2/IFRS 2, leasing transactions that are within the scope of MFRS 16/MFRS 117/IFRS 16/ IAS 17, and measurements that have some similarities to fair value but are no fair value, such as net realisable value in MFRS 102/ IAS 2 or value-in-use in MFRS 136/IAS 36.

In addition, for financial reporting purposes, fair value measurements are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value measurements are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

3.3 Classification of assets and liabilities into current and non-current

In the accompanying statement of financial position, assets and liabilities maturing within twelve months are classified as current items and those maturing in more than twelve months are classified as non-current items.

3.4 Impairment of investments

Investments in group companies, jointly controlled entities and associates are initially measured at cost, which is equivalent to the fair value of the consideration given plus directly attributable transaction costs. Initial measurement shall include any pre-emptive and similar rights acquired. These financial assets are subsequently measured at cost less any accumulated impairment.

At least at the balance sheet date, the company recognises any necessary valuation allowances when there is objective evidence that the carrying amount of an investment will not be recovered. Impairment is assessed on annual basis in accordance to Group's accounting policies. The impairment loss is measured as the difference between the carrying amount and the recoverable amount. The recoverable amount is the higher of the fair value less costs to sell and the present value of future cash flows from the investment, estimated as either those from dividends expected to be received from the investee and the disposal or derecognition of the investment, or from the share in the cash flows expected to be generated by the investee in the ordinary course of business and from disposal or derecognition.

If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized as an expense in the statement of profit or loss and other comprehensive income.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined in case no impairment loss had been recognized for the asset in prior years.

3.5 Financial assets

Classification

The Company classifies its financial assets at the time it is initially recognised and is subsequently measured at either amortised costs, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL").

The classification of financial asset at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing the financial assets. For assets measured at fair value, gains and losses will either be recorded in profit or loss or other comprehensive income ("OCI"). For investments in equity instruments that are not held for trading, this will depend on whether the Company has made an irrevocable election at the time of initial recognition to account for the equity investment at FVOCI.

The Company reclassifies debt investments when and only when its business model for managing those assets change.

Recognition and initial measurement

At initial recognition, with the exception of trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at FVTPL, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are expensed in profit or loss. Trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient is measured at the transaction price as determined under MFRS 15/IFRS 15.

Financial assets with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

Subsequent measurement

Subsequent measurement of debt instruments depends on the Company's business model for managing the asset and the cash flow characteristics of the asset. There are three measurement categories into which the Company classifies its debt instruments:

a) Debt instruments

i. Amortised cost

Assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortised cost. Interest income from these financial assets is included in finance income using the effective interest rate method. Any gain or loss arising on derecognition of the Company's financial assets are recognised directly in profit or loss and presented in other operating gains/(losses). Impairment losses are presented as separate line item in the statement of profit or loss and other comprehensive income.

ii. FVTPL

Assets that do not meet the criteria for amortised cost or FVOCI are measured at FVTPL. A gain or loss on a debt investment that is subsequently measured at FVTPL is recognised in profit or loss and presented net within other operating gains/(losses) in the period in which it arises.

b) Equity instrument

FVOCI

Assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Movements in the carrying amount are taken through OCI, except for the recognition of impairment gains or losses, interest revenue and foreign exchange gains and losses which are recognised in profit or loss. When the financial asset is derecognised, the cumulative gain or loss previously recognised in OCI is reclassified from equity to profit or loss and recognised in other operating gains/(losses). Interest income from these financial assets is included in finance income using the effective interest rate method.

Foreign exchange gains and losses and impairment expenses are presented in other operating gains/(losses). When it is deemed to be material in nature, the impairment expenses shall be presented as separate line item in the statement of profit or loss and other comprehensive income.

Impairment of financial assets

The Company assesses on a forward looking basis the expected credit losses ("ECL") associated with its debt instruments carried at amortised cost. The amount of the expected credit losses is updated at the end of each reporting period to reflect changes in credit risk since initial recognition of the respective financial instrument.

The expected credit losses on these financial assets are estimated using a provision matrix based on the Company's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. For all other financial instruments, the Company recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the Company measures the loss allowance for that financial instrument at an amount equal to 12 month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12 month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

Significant increase in credit risk

The Company considers the probability of default upon initial recognition of asset and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. To assess whether there is a significant increase in credit risk, the Company compares the risk of a default occurring on the asset as at the reporting date with the risk of default as at the date of initial recognition. It considers available reasonable and supportable forward looking information that includes historical default rate, internal and external credit rating (as applicable), actual or expected changes in economic and regulatory environment that are expected to cause a significant change to the debtor's ability to meet its obligations.

A significant increase in credit risk is presumed if a debtor become inactive, indication of consistent delay in making contractual payments that are long past due with history of default or the debtor is expected to/or is experiencing significant financial difficulties and cash flow problems.

Derecognition of financial assets

Financial assets are derecognised when the contractual rights to receive cash flows from the financial assets have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Any gain or loss arising on derecognition is recognised directly in profit or loss and presented in other gains/(losses) together with foreign exchange gains and losses.

3.6 Financial liabilities

Classification

Financial liabilities are classified according to the substance of the contractual arrangements entered into and the definitions of a financial liability. Management determines the classification of financial liabilities at initial recognition.

Financial liabilities are recognised in the statements of financial position when, and only when, the Company become a party to the contractual provisions of the financial instrument. The Company classifies all its financial liabilities as other financial liabilities.

Recognition and initial measurement

Trade and other payables are recognised initially at fair value net directly attributable transaction costs and subsequently measured at amortised cost using the effective interest method.

Loans and borrowings are recognised initially at fair value, net of transaction costs incurred and subsequently measured at amortised cost using the effective interest method. Borrowings are classified as current liabilities unless the Company have an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

Derecognition of financial liabilities

A financial liability is derecognised when the obligation under the liability is extinguished. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in the statements of comprehensive income.

3.7 Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when there is a legally enforceable right to offset the recognised amounts and there is an intention to settle on a net basis, or realise the asset and settle the liability simultaneously. The legally enforceable rights must not be contingent on future events and must be enforceable in the normal course of business and in the event of default, insolvency or bankruptcy.

3.8 Cash and cash equivalents

The Company classifies under " *Cash and cash equivalents* " in the statement of financial position liquid financial assets, deposits or financial assets that can be converted into a known amount of cash three months from initiation to maturity and that are subject to an insignificant risk of changes in value.

3.9 Loan and receivables

Loan and receivables are recognised initially at fair value and subsequently measured at amortised costs using the effective interest method, less loss allowance. The impairment policy for loan and receivables is in accordance with that for impairment of financial assets as described in Note 3.5 to the financial statements.

3.10 Provisions and contingent liabilities

In accordance with prevailing accounting standards, the Company makes a distinction between:

a) Provisions: present obligations, either legal or assumed by the Company, arising from past events, the settlement of which is probable to give rise to an outflow of resources the amount and timing of which are uncertain; and

b) Contingent liabilities: possible obligations that arise from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more future events not wholly within the control of the Company, or present obligations arising from past events, the amount of which cannot be measured with sufficient reliability or whose cancellation is not likely to give rise to an outflow of resources embodying future economic benefits.

These provisions are recognized when the liability or obligation giving rise to the indemnity or payment arises, to the extent that its amount can be reliably estimated and it is probable that the commitment will have to be settled.

Contingent liabilities are not recognized as provisions in the financial statements. Notwithstanding the above, whenever it is deemed as non-remote that settlement of such a liability will give rise to an outflow of resources, the existence of these liabilities is disclosed.

3.11 Revenues and expenses recognition

Interest income is accrued on a time proportion basis, by reference to the principal outstanding and the effective interest rate applicable.

An expense is recognized when there is a decrease of economic benefits associated to a reduction of an asset, or an increase in a liability, whichever can be measured reliably.

3.12 Financing costs

Financing costs comprise interest payable on borrowings and any accretion in provision due to the passage of time.

3.13 Income Tax

The Company recognizes in the statement of profit or loss and other comprehensive income for the year the accrued tax on the Company's income, which is calculated taking into account the differences between the timing of recognition for accounting purposes and tax purposes of the transactions and other events in the current year recognized in the financial statements, giving rise to temporary differences and, therefore, to the recognition of certain deferred tax assets and liabilities in the statement of financial position. These amounts are recognized by applying to the temporary differences the tax rate that is expected to apply in the period when the asset is realized, or the liability is settled.

Deferred tax liabilities are recognized for all taxable temporary differences, unless the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets recognized for temporary differences and other deferred tax assets (tax losses and tax deductions carry forwards) are recognized when it is considered probable that the Company will have sufficient taxable profits in the future against which the deferred tax asset can be utilized. Deferred tax assets relating to the carry forward of unused tax losses are recognised to the extent that it is probable that future taxable profit will be earned against which the unused tax losses can be utilised.

The accrued income tax expense includes both the deferred income tax expense and the current income tax expense, which is taken to be the amount payable (or refundable) in relation to the taxable net income for the year (see Note 11).

"*Income tax expense*" in the statement of profit or loss and other comprehensive income includes both the accrued income tax expense and the net provisions recognized in the year for uncertain tax position, insofar as the latter relate to income tax.

Current and deferred taxes are recognized outside statement of profit or loss and other comprehensive income if they are related to items that are recognized outside the statement of profit or loss and other comprehensive income. Those entries related to items recognized under "Adjustments for changes in value" are recognized under that heading and those recognized directly in equity are recognized within the equity.

3.14 Foreign Currency

The Company's functional and presentation currency is United States dollars. Transactions in currencies other than the functional currency are deemed to be 'foreign currency transactions' and are translated to the functional currency by applying the exchange rates prevailing at the date of the transaction. At each year end, the foreign currency monetary items on the statement of financial position are measured applying the exchange rate prevailing at that date and the exchange rate differences arising from such measurement are recorded as "foreign exchange gain/(loss)" within "Financial result" in the statement of profit or loss and other comprehensive income in the year incurred.

3.15 Transactions with related parties

The Company performs all its operations with related parties at agreed terms and prices, which is why management considers that there are no significant risks from this aspect from which future liabilities may arise.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

4.1 Critical judgements in applying the Company's accounting policies

In the process of applying the Company's accounting policies, which are described in Note 3 above, management is of the opinion that there are no instances of application of judgement which are expected to have a significant effect on the amounts recognised in the financial statements.

4.2 Key sources of estimation uncertainty

The information included in these financial statements is the responsibility of the management of the Company.
In the financial statements for the year 2020, 2019 and 2018, on occasions estimations made by the management of the Company have been used to evaluate some of the assets, liabilities, income, expenses and commitments that are recorded in the accounts. Basically, those estimations, made according to the best information available, relate to:

- Assessment of potential impairment losses on investment in subsidiaries
- Calculation of income tax, tax credit and deferred tax assets

4.2.1 Assessment of potential impairment losses on investment in subsidiaries

In order to ascertain whether investment in subsidiaries have become impaired, the Company compares the carrying amount with the recoverable amount at least annually and whenever there are indications that the investment in subsidiaries might have become impaired ("impairment test"). If the recoverable amount of the investment in subsidiaries estimated to be less than its net book value, the carrying amount is reduced to its recoverable amount, and an impairment loss is recognized in the statement of profit or loss and other comprehensive income. The Company's accounting policies on impairment on investment in subsidiaries are disclosed in Notes 3.4.

On the occurrence of new events, or changes in existing circumstances, which prove that an impairment loss recognized on a prior date no longer exists or has decreased, a new estimate of the recoverable value of the corresponding asset is developed, to determine whether it is appropriate to reverse the impairment losses recognized in previous periods.

In the event of a reversal of an impairment previously recorded, the carrying amount of the investment in subsidiaries is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized in prior years.

In determining the recoverable amount for the investment in subsidiaries, the present value of the future cash flows from operations have deducted the present value of the projected financing cash flows of the subsidiaries to derive the net cash flows attributable to the Company.

For the "impairment test", in determining the recoverable amouunts of the respective subsidiaries, assets are grouped into cash-generating units (CGUs), to the extent that such assets, when individually considered, do not generate cash inflows that are independent of the cash inflows from other assets or CGUs. The grouping of assets into the various CGUs requires the use of professional judgments and the determination, among other criteria, of the business segments and geographic areas in which the Company operates. In the upstream segment, each CGU corresponds to one of the various contractual exploration areas widely known as "blocks" exceptionally, if the cash flows generated by more than one block are mutually interdependent, those blocks will be grouped into a single CGU.

The recoverable amount is the higher of fair value less costs of sale and value in use.

The methodology used by the Company to estimate the recoverable amount of assets is, in general, the value in use calculated by discounting to present value the future cash flows after tax expected to be derived from the operation of these assets.

The cash flow projections are based on the best available estimates of the CGUs' income and expenses using sector forecasts, prior results and the outlook for the business's performance and market's development:

- Macroeconomic variables are those used in the preparation of the budgets. The macroeconomic framework for the countries in which the Group operates takes into consideration variables such as inflation, GDP, exchange rate, etc. and is prepared on the basis of the content of internal reports that use in-house estimates, based on updated external information of relevance (forecasts prepared by consultants and specialized entities).

- The oil and natural gas price paths used for the impairment test are our own estimates, although they are consistent or in line with the view of prices established by the various international benchmark agencies, including the International Energy Agency ("IEA"). The paths are developed on the basis of available macroeconomic, financial and market information and the forecasts provided by analysts and they consider scenarios for the energy transition and decarbonisation of the economy that are consistent with the commitments assumed to achieve the objectives of the Paris Climate Summit.
In particular, crude oil and gas prices are calculated by analysing key market variables and their foreseeable trend, including our own forecasts of the balance of supply and demand of energy and prices. The longer-term vision is also explained by monitoring other variables such as: the decline, the current CAPEX, the financial sustainability of companies in the sector to certain price environments, and the dynamics in OPEC countries in terms of fiscal sustainability. Econometric models of prices are made with all these elements, which are compared with both public and private external forecasts.

i. To estimate near-term price trends, we basically use forecast reports produced by a selection of, investment banks, macro consultants and international benchmark agencies are taken into account.
ii. The sources that present a sufficiently detailed analysis of long-term forecasts are the macro consultants and benchmark agencies (IEA and EIA), which also carry out detailed studies of supply, demand and price forecasts under different scenarios

The assumptions for the main price references for 2018 are as follows:

	2019	2020	2021	2022	2023	2024	2025	2026	2027-2032
Brent ($/ barrel)	65	70	75	81	86	89	92	94	97

The assumptions for the main price references for 2019 are as follows:

	2020	2021	2022	2023	2024	2025	2026-2030	2031-2032
Brent ($/ barrel)	65	69	70	71	72	74	81	87

In 2020, in view of the situation in the commodity markets and in particular the social and economic consequences of the COVID-19 pandemic and the foreseeable development of the energy transition, the Group reviewed its expectations of future oil and gas prices, modifying the price paths defined at the end of 2019 to bring them into line with the new scenario.

It should be noted that these estimates were made in an environment of high uncertainty, marked by the scenarios of emerging from the COVID-19 crisis, by the dynamics of the energy transition and decarbonisation of the economy and, in short, by their possible impacts on the Oil & Gas markets.

- The Brent's path was revised downwards in the short and medium term (until 2024) as a result of a contraction in the demand for oil never seen before and a reaction of supply that was insufficient to adjust to the low demand, despite the fact that the OPEC+ made the biggest production cut in its history and other producers have also taken heavy cuts.

- The Henry Hub path was revised upwards for 2021, due to the drop in gas production and the boost in the demand for gas for the electricity industry and electricity generation in the US, and the path was revised downwards in the medium and long term due to the expectation of greater penetration of renewable energies on a global scale and the consolidation of excess supply in the face of falling global demand.

The new assumptions for the main price references are as follows:

	2021	2022	2023	2024	2025	2026-2032
Brent ($/ barrel)	49	55	58	62	67	59

Future cash flows are discounted to their present value at a specific rate for each CGU, determined based on the currency of its cash flows and the risks associated with them. The discount rate used by the Company is the weighted average cost of capital employed after tax for each country and business.

Cash flows are estimated on the basis of the outlook for their key variables in accordance with the expectations reflected in the annual budget and in the strategic plans for each business, in line with the new scenario of energy transition and decarbonization of the economy.

The discount rates used in 2020, 2019 and 2018 are as follows:

2020	2019	2018
7.36%	7.62%	8.16%

Valuations of the production assets of Exploration and Production (Upstream) use cash flow projections for a period that covers the economically productive useful lives of the oil and gas fields, limited by the contractual expiration of the operating permits, agreements or contracts. The general principles applied to determine the variables that most affect the cash flows of this business are described below:

- Oil and gas sales prices. The international benchmark price used by the Group are: Brent and HH (Henry Hub).

- Reserves, resources and production profiles. Production profiles are estimated on the basis of output levels at existing wells and the development plans in place for each productive field. As a consequence, these profiles are then used to estimate proved and unproved reserves and resources.

- Operating expenses and capital expenditure. These are calculated for the first year on the basis of the Group's annual budget and thereafter in keeping with the asset development programs, applying an escalation factor for operating expenses and investments basically of -1% to 1% (1%-1.5% in 2019, 2% in 2018).

4.2.2 Calculation of income tax, tax credit and deferred tax assets

The appropriate assessment of the income tax expense is dependent on several factors, including estimates of the timing and realization of deferred tax assets and the timing of income tax payments. Actual collections and payments may differ materially from these estimates as a result of changes in tax laws as well as unanticipated future transactions impacting the Company's tax balances.

Deferred tax assets are only recognized when it is considered probable that the Company will have sufficient taxable income in the future against which they can be utilized.

Deferred tax assets are reviewed when there are indications of impairment, and in any event once a year, to verify that they still qualify for recognition and they are considered to be recoverable in the future, and the appropriate adjustments are made on the basis of the outcome of the analyses performed. These analyses are based on: (i) assumptions made to analyse the existence or otherwise of sufficient future earnings for tax purposes that might offset the tax losses or apply existing tax credits, based on the approach used to ascertain the presence of indications of impairment on its assets; (ii) the assessment of earnings estimates for the Company in accordance with the Company's business plans and the Group's overall strategic plan; and (iii) the statute of limitations period and other utilization limits imposed under prevailing legislation in the country for the recovery of the tax credits.

Although these estimations have been made on the basis of the best information available at December 31, 2020, 2019 and 2018 on the facts analysed, it is possible that events that might take place in the future could mean modifying them *(increasing or decreasing)* in the coming years, which would, if the case arises, be carried out prospectively, recognising the effects of the change in estimation in the income statements for the years in question.

5. RISK MANAGEMENT

The Company is exposed to various risks that are particular to holding companies. These risks arise in the normal course of the Company's business.

The Company's goal in risk management are to ensure that the management understands, measures and monitors the various risks that arise in connection with their operations. Policies and guidelines have been developed to identify, analyse, appraise and monitor the dynamic risks facing the Company. Based on this assessment, each business unit adopts appropriate measures to mitigate these risks in accordance with the business unit's view of the balance between risk and reward.

The Company has exposure to foreign exchange risk, liquidity risk and credit risk arising from its use of financial instruments in the normal course of the Company's businesses.

5.1 Liquidity risk

The Company actively manages its debt maturity profile, operating cash flows and the availability of funding to ensure that all refinancing, repayment and funding needs are met. As part of its overall prudent liquidity management, the Company maintains sufficient levels of cash or cash convertible investments to meet its working capital requirements. In addition, the Company strives to maintain available banking facilities of a reasonable level to its overall debt position.

The table below summarises the maturity profile of the Company's financial liabilities at the reporting date based on contractual undiscounted repayment obligations with a maturity of less than 3 months:

	USD'000 2020	USD'000 2019	USD'000 2018
Trade and account payables			
- Less than one year	25	20	18
Total	**25**	**20**	**18**

5.2 Credit risk

Credit risks, or the risk of counterparties defaulting, are controlled by the application of credit approvals, limits and monitoring procedures. The Company is exposed to credit risk, which is the risk that a counterparty will fail to perform an obligation or settle a liability, resulting in credit loss to the Company. The Company's concentration of credit risk is mitigated by dealing with generally credit worthy group companies.

The maximum exposure to credit risk for the Company is represented by the carrying amount of each financial asset.

The Company's exposure to credit risk, according to the type of financial instrument together with the impairment recognized at December 31, 2020 for each of them, is broken down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Loans to related parties			
- Not due	473	354,702	346,774
Cash and cash equivalents			
- Not due	12	18	72
Total	**485**	**354,720**	**346,846**

The expected credit loss for loans to related parties, cash and cash equivalents at December 31, 2020, 2019 and 2018 are immaterial.

5.3 Interest rate risk

The Company is not exposed to significant interest rate risk.

5.4 Other risks

On March 11, 2020, the World Health Organization raised to the status of global pandemic the public health emergency caused by SARS-CoV-2 virus (commonly known as coronavirus, while COVID-19 denotes the disease caused by the virus). The rapid spread of COVID-19, on an international scale, has triggered an unprecedented healthcare, social and economic crisis that continues to evolve.

The economic impact of the pandemic, combined with pre-existing complications on the supply and demand side, has resulted in an exceptionally challenging pricing environment for oil and gas.

Even amid these difficult circumstances, the Company has sustained the safe operation of its business.

It is difficult to predict to what extent and for how long the impact of the pandemic will affect the Company's business in the future. The lower global demand for crude oil, gas and oil products as a result of the reduction in economic activity and, in particular, the restrictions to mobility, may have a negative impact on prices, production levels and sales volumes, the deterioration of global financial conditions may affect the cost of capital, liquidity or solvency on our customers and partners in joint operations, and so on.

6. Financial Instruments

All the financial assets and financial liabilities of Company are measured at amortised costs. The following table analyses the financial assets and financial liabilities in the statement of financial position by the class of financial instruments to which they are assigned, and therefore by the measurement basis:

6.1 Classification of financial instruments

	USD'000 2020	USD'000 2019	USD'000 2018
Financial assets			
Amortised cost:			
Loans to related parties	473	354,702	346,774
Cash and cash equivalents	12	18	72
Total	**485**	**354,720**	**346,846**
Financial liabilities			
Amortised cost:			
Due to related parties	-	-	7
Trade and account payables	25	20	18
Total	**25**	**20**	**25**

7. Capital risk management

Capital management is defined as the process of managing the composition of the Company's debts.

The Company operates within clearly defined guidelines that are approved by Repsol, S.A., which is the ultimate holding company and it relies on the ultimate holding company for funding to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities as and when they fall due.

8. Investments in subsidiaries

	USD'000
Balance at January 1, 2018	**181,074**
Additions/Disposals	-
Impairment	-
Balance at December 31, 2018	**181,074**
Additions/Disposals	-
Impairment	-
Balance at December 31, 2019	**181,074**
Additions/Disposals	-
Impairment reversal	-
Balance at December 31, 2020	**181,074**

The Company owns 100% of the issued and outstanding shares of RML, RMPM3 and TVL.

The Company has assessed the recoverable amount as described in Note 4.2.1. Based on the analysis performed, no impairment was recognised as of December 31, 2020, 2019 and 2018.

The details of the investments in subsidiaries are as follows:

Name	Country of Incorporation	Principal place of business	Activity	Ownership Direct %	Ownership Indirect %
RML	Barbados	Malaysia	Exploration, development, production and marketing of crude oil, natural gas and natural gas liquids in Malaysia and Vietnam	100	-
RMPM3	Barbados	Malaysia		100	-
TVL	Barbados	Malaysia		100	-

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9. Loans to related parties

	USD'000 TEHS	USD'000 RIF	USD'000 Total
Balance at January 1, 2018	**549,255**	**-**	**549,255**
Repayments during the year	(209,903)	-	(209,903)
Interest during the year	3,816	3,606	7,422
Transfer of loan	(343,168)	343,168	-
Balance at December 31, 2018	**-**	**346,774**	**346,774**
Interest during the year	-	7,928	7,928
Balance at December 31, 2019	**-**	**354,702**	**354,702**
Repayments during the year	(100)	(60)	(160)
Interest during the year	719	2,212	2,931
Transfer of loan to RIF	356,854	(356,854)	-
Transfer of loan from TVL	10,000	-	10,000
Transfer of loan to REXSA	(367,000)	-	(367,000)
Balance at December 31, 2020	**473**	**-**	**473**

TEHS and RIF,each of whom share a common ultimate holding company (Repsol, S.A) with the Company. These companies provide treasury function of Repsol Group to the Company.

On November 1, 2017, the Company and TE Holding S.A.R.L. ("TEHS") entered into a deposit contract that matured on November 30, 2018. This loan has a floating interest rate which is reset every month and based on 1-month LIBOR. Accrued interest is due on repayment of borrowings and any outstanding interest payable at month end if not paid in cash is added to the principal. The loan was transferred to Repsol International Finance B.V. ("RIF") on July 13, 2018 with the new maturity date on November 30, 2019. On December 31, 2018, the balance of the loan principal was $346,726 thousand plus accrued interest $48 thousand.

On November 30, 2019 the Company signed an annex to the credit contract dated on July 13, 2018 to modify the clauses regarding maturity date until 30 November, 2020, and interest rate to 3-month LIBOR minus 5 basis point. The principal outstanding at December 31, 2019 is $354,118 thousand plus accrued interest of $584 thousand.

On November 13, 2020, the Board of Directors decided to reassign the deposit contract to TE Holding S.A.R.L. ("TEHS") through an amendment with effective date as of November 30, 2020.

On November 30, 2020, the Company signed the amendment to the deposit agreement dated on November 1, 2017 and modified the clauses regarding maturity date until November 30, 2021, and interest rate to 3-month LIBOR minus 6 basis point.

On December 15, 2020, the Company's subsidiary, Talisman Vietnam Limited ("TVL"), declared and paid a dividend of $10,000 thousand to the company by way of transfer of the loan due from TEHS to the Company. The Company then declared and paid a dividend of $96,772 thousand and share capital returns of $270,228 thousand to its immediate parent Repsol Exploración S.A. ("REXSA") by way of transfer of the loan due from TEHS amounting to $367,000 thousand to REXSA.

The principal outstanding at December 31, 2020 is $445 thousand plus accrued interest of $28 thousand.

10. Share Capital

The company is authorised to issue an unlimited number of shares of a class designated Common Shares at no par value and an unlimited number of shares of a class designated First Preferred Redeemable Shares.

On April 17, 2018, the Company converted First Preferred Redeemable Shares of 186,049,000 in the amount of $186,049 thousand into class A Common Shares of the Company.

On December 16, 2020, the Company proposed to return the common shares of the company by the amount of $270,228 thousand (465,585,726 shares) to Repsol Exploración S.A.

As at December 31, 2020, total shares issued are 313,736,062 (2019: 779,321,788) in the amount of $182,094 thousand (2019: $452,322 thousand).

	Number of Shares	USD'000 Amount
Balance at January 1, 2018	**593,272,788**	**456,273**
Return of capital	-	(190,000)
Addition of capital	186,049,000	186,049
Balance at January 1, 2019 and December 31, 2018	**779,321,788**	**452,322**
Return of capital	-	-
Addition of capital	-	-
Balance at January 1 2020 and December 31, 2019	**779,321,788**	**452,322**
Return of capital	(465,585,726)	(270,228)
Addition of capital	-	-
Balance at December 31, 2020	**313,736,062**	**182,094**

As of December 31, 2020 and 2019, Repsol Exploración S.A. owns 100% of the Company's share capital. The shares of the Company are not listed in any Stock Exchange Market.

11. Income taxes

	USD'000 2020	USD'000 2019	USD'000 2018
Tax income/(expense) attributable to profit is made up of:			
CURRENT CORPORATE INCOME TAX			
Prior year adjustments	(135)	-	908
Total	**(135)**	**-**	**908**
DEFERRED CORPORATE INCOME TAX			
Prior year adjustment - Derecognition of Deferred tax Liability	-	-	2,219
Deferred tax write off	(1,175)	-	350
Tax losses offset	(36)	(118)	(126)
Total	**(1,211)**	**(118)**	**2,443**
Total income tax expense	**(1,346)**	**(118)**	**3,351**

The Company accounts for income taxes using the tax liability method. As a result, the Company's income tax expense varies from the amount that would otherwise result from the application of the statutory income tax rates as set out below:

	USD'000 2020	USD'000 2019	USD'000 2018
Profit before income tax	12,877	7,881	7,320
Expected income tax expense at Barbados corporate tax rate of 2.5% (1.5% in 2019; 1.5% in 2018)	(322)	(118)	(110)
(Decrease)/increase in income tax expense resulting from:			
Non-deductible expense	286	-	(16)
Derecognition of deferred tax	-	-	2,219
Deferred tax write off	(1,175)	-	350
Prior year adjustments	(135)	-	908
Income tax expense	**(1,346)**	**(118)**	**3,351**

The movement of the deferred tax assets/(liabilities) of the Company are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
At 1 January	1,211	1,329	(1,114)
Taxable losses offset	(36)	(118)	(126)
Derecognition of deferred tax asset	(1,175)	-	-
Derecognition of deferred tax liability	-	-	2,219
Prior year adjustment – tax losses	-	-	350
At 31 December	-	1,211	1,329

The components and movements of deferred tax liabilities and assets during the financial year mainly attributable to tax losses.

Deferred tax asset write-off is attributable to the compensation of the credit loan and the lack of taxable income in future years.

The Company has cumulative tax losses of $84M, which will expire in 2024 for which no deferred tax asset has been recognised due to the lack of future taxable income. Losses may be carried forward for 7 years but limited to 50% of the taxable base.

The Company was previously licensed under the International Business Companies Act Cap. 77 which has been repealed. The Company continues its licensing under the Companies Act Cap. 308. which allows provision for the same previous benefits via grandfathering under the International Business Companies (Repealed) Act, 2018- 40, until the Company transitions to the new regime in June 2021.The Company qualified for grandfathering. As a result, the tax rates remain at 1.0% to 2.5%. On the repeal of the International Business Companies Act, Cap. 77., the Income Tax Act Cap. 73 was amended to apply new staggered tax rates from 1.0% to 5.5% based on the Company's taxable income (2019 – 1.0% to 2.5%).

The revised tax rates effective January 1, 2020 are as follows: taxable income up to $500 Thousand is subject to tax at 5.5%, taxable income exceeding $500 Thousand up to the next $10,000 Thousand at 3.0%, taxable income exceeding $10,000 Thousand up to $15,000 Thousand at 2.5% and all amounts in excess of $15,000 Thousand at 1.0%.

12. Revenue

The breakdown of the balance for this financial statement line on the income statement is as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Interest income from affiliates (Note 9)	2,931	7,928	7,422
Dividend income - TVL	10,000	-	-
Other income			3
Total revenue	12,931	7,928	7,425

On December 15, 2020, the Company's subsidiary Talisman Vietnam Limited ("TVL") declared and paid a dividend of $10,000 thousand to the company by way of transferring the loan due from TE Holding S.A.R.L. ("TEHS") to the company.

13. Staff costs

Fortuna International Petroleum Corporation does not have any personnel. Hence, no staff costs were incurred during the year.

14. Related parties

14.1 Related parties' balances and transactions

Balances with related parties as at December 31, 2020 and 2019 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Loans to related companies:			
TE Holding S.a.r.l.	473	-	-
Repsol International Finance	-	354,702	346,774
Loans to related parties	**473**	**354,702**	**346,774**
Amount due to related company:			
TE Holding S.a.r.l.	-	-	7
Due to related party	**-**	**-**	**7**

The amounts due to/from related parties which mainly arose from non-trade transactions are unsecured, non-interest bearing and are repayable on demand.

Loan to related party is detailed in Note 9.

The material related party transactions for 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Dividends received from:			
- Talisman Vietnam Limited	10,000	-	-
Total dividend income	**10,000**	**-**	**-**
Interest income from:			
- TE Holding S.a.r.l.	719	-	3,816
- Repsol International Finance	2,212	7,928	3,606
Total interest income	**2,931**	**7,928**	**7,422**

14.2 Information referring to the Directors

Remuneration and other benefits paid to the Directors

In 2020, the Company has paid $4 thousand to its Directors for attending to the functions inherent to the Company management ($6 thousand in 2019, $5 thousand in 2018).

At December 31, 2020 and 2019, the Company had not assumed any obligations regarding pensions or life insurance for its Directors, nor were any advances, loans or credits made to them by the Company.

15. Events subsequent to year end

Since the end of 2020, there have been no significant events.

Effective June 30, 2021 the benefits under the International Business Companies Act (Repealed) Act 2018-40 will expire. The company will be required to comply with the Companies (Economic Substance) Act, 2019-43 (CESA) with effect from January 1, 2021. The Act imposes an economic substance test on Barbados-resident companies that are managed and controlled in Barbados or incorporated/registered in Barbados and not considered a tax resident in another jurisdiction. The Act also requires that the companies conduct relevant activities as defined under the Act. The Company is in compliance with the new Act based on the management's assessment.

16. Other information

16.1 Audit fees

The fees relating to the audit of the annual accounts of the Company for the year 2020 amounted to $15.2 thousand ($14.8 thousand in 2019; $14.5 thousand in 2018). During 2020 neither the Company's auditor nor other companies related to it through control, ownership or management, have provided the Company with services additional to those for audit of the annual accounts.

16.2 Contingent liabilities

At December 31, 2020, 2019 and 2018, the Company had not assumed any tax or legal contingent liabilities.

The Board of Directors
Hibiscus Petroleum Berhad
2nd floor,
Syed Kechik Foundation Building,
Jalan Kapas, Bangsar,
59100 Kuala Lumpur.

4 October 2021

PwC/TEH/NNH/sw/0898B1

Dear Sirs,

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia Limited

<u>Our Opinion</u>

We have audited the accompanying financial statements of Repsol Oil & Gas Malaysia Limited ("RML" or the "Target Company") which comprise the statements of financial position as at 31 December 2018, 31 December 2019 and 31 December 2020, the statements of profit or loss and other comprehensive income, statements of changes in shareholder's equity and statements of cash flows for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, and a summary of significant accounting policies and other explanatory notes (together, the "Financial Statements"), as set out on pages 1 to 47. The Financial Statements have been prepared for purposes of inclusion in Hibiscus Petroleum Berhad ("HPB")'s circular to shareholders of HPB (the "Circular to Shareholders") in connection with the proposed acquisition of Fortuna International Petroleum Corporation and its subsidiaries by HPB (the "Proposal").

In our opinion, the Financial Statements give a true and fair view of the financial position of the Target Company as at 31 December 2018, 31 December 2019 and 31 December 2020 and of its financial performance and cash flows for each of the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS").

PricewaterhouseCoopers PLT (LLP0014401-LCA & AF 1146), Chartered Accountants, Level 10, 1 Sentral, Jalan Rakyat, Kuala Lumpur Sentral, P.O. Box 10192, 50706 Kuala Lumpur, Malaysia
T: +60 (3) 2173 1188, F: +60 (3) 2173 1288, www.pwc.com/my

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0898B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia Limited (Continued)

Basis for Opinion

We conducted our audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing. Our responsibilities under those standards are further described in the Reporting Accountant's Responsibilities for the Audit of the Financial Statements section of our report. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence and Other Ethical Responsibilities
We are independent of the Target Company in accordance with the By-Laws (on Professional Ethics, Conduct and Practice) of the Malaysian Institute of Accountants ("By-Laws") and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) ("IESBA Code"), and we have fulfilled our other ethical responsibilities in accordance with the By-Laws and the IESBA Code.

Directors' Responsibilities for the Financial Statements

The Directors of the Target Company are responsible for the preparation of the Financial Statements for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020 that gives a true and fair view in accordance with the MFRS and IFRS. The Directors of the Target Company are also responsible for such internal control as the Directors of the Target Company determine is necessary to enable the preparation of the Financial Statements that is free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements of the Target Company, the Directors of the Target Company are responsible for assessing the Target Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors of the Target Company either intend to liquidate the Target Company or to cease operations, or have no realistic alternative but to do so.

Reporting Accountant's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements of the Target Company as a whole are free from material misstatement, whether due to fraud or error, and to issue a report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with approved standards on auditing in Malaysia and International Standards on Auditing will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0898B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia Limited (Continued)

Reporting Accountant's Responsibilities for the Audit of the Financial Statements (Continued)

As part of an audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Financial Statements of the Target Company, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Target Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors of the Target Company.
- Conclude on the appropriateness of the Directors of the Target Company's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Target Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our report to the related disclosures in the Financial Statements of the Target Company or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our report. However, future events or conditions may cause the Target Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the Financial Statements of the Target Company, including the disclosures, and whether the Financial Statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Directors of the Target Company regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0898B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia Limited (Continued)

Restriction on Distribution and Use

This report is issued for the sole purpose of inclusion in the Circular to Shareholders of HPB in connection with the Proposal, and should not be relied on for any other purposes. Accordingly, we will not accept any liability or responsibility to any other party to whom our report is shown or into whose hands it may come.

Yours faithfully,

PricewaterhouseCoopers PLT

PRICEWATERHOUSECOOPERS PLT
LLP0014401-LCA & AF 1146
Chartered Accountant

REPSOL OIL & GAS MALAYSIA LIMITED

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

Repsol Oil & Gas Malaysia Limited

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

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Repsol Oil & Gas Malaysia Limited

STATEMENTS OF FINANCIAL POSITION

(U.S. dollars)	Note	USD'000 As at 31.12.2020	USD'000 As at 31.12.2019	USD'000 As at 31.12.2018
Assets				
Intangible assets	9	2,149	1,685	972
Property, plant and equipment	10	241,286	333,217	351,876
Right-of-use assets	11	16,281	31,693	-
Sinking fund	13	72,528	60,749	52,384
Long-term income tax receivable	21	6,387	6,387	9,182
Deferred tax assets	21	30,415	36,336	72,918
Non-current Assets		**369,046**	**470,067**	**487,332**
Inventories	15	16,468	16,982	18,196
Trade and other receivables	14	51,005	79,627	43,733
Loan to related party	16,23	12,703	18,995	-
Due from related parties	23	2,172	3,067	1,508
Cash and cash equivalents		48,090	68,885	81,283
Current Assets		**130,438**	**187,556**	**144,720**
Total Assets		**499,484**	**657,623**	**632,052**
Shareholder's equity and Liabilities				
Share capital	20	12	12	12
Reserves		124,426	124,426	124,426
Retained earnings		81,516	202,902	179,861
Shareholder's equity		**205,954**	**327,340**	**304,299**
Asset retirement obligation	18	131,325	128,465	135,569
Non-current provisions	18	298	296	500
Long-term payable	17	2,041	1,611	19,148
Long-term lease obligation	17	25,204	30,374	20,540
Non-current Liabilities		**158,868**	**160,746**	**175,757**
Asset retirement obligation	18	12,777	-	79
Current provisions	18	242	420	66
Due to related parties	23	1,111	7,401	2,673
Loans from related parties	16,23	-	-	10,968
Trade and other payables	17	61,635	149,854	138,210
Income tax payable	21	58,897	11,862	-
Current Liabilities		**134,662**	**169,537**	**151,996**
Total Shareholder's equity and Liabilities		**499,484**	**657,623**	**632,052**

Notes 1 to 27 are an integral part of the financial statements.

Approved by Khoo Pooi Yin on behalf of the Directors on October 4, 2021:

Repsol Oil & Gas Malaysia Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Repsol Oil & Gas Malaysia Limited

STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
FOR THE YEARS ENDED

(U.S. dollars)	Note	USD'000 31.12. 2020	USD'000 31.12.2019	USD'000 31.12.2018
Sales	12,22a	192,029	252,712	316,151
Revenue		**192,029**	**252,712**	**316,151**
Gains on disposal of non-current assets		-	13	-
Change in underlift		(9,848)	10,126	(4,666)
Supplies		(3,244)	(8,974)	4,376
Personnel expenses	22b	(36,831)	(48,715)	(59,812)
Other operating expenses	22d	(85,530)	(109,397)	(133,611)
Depletion, depreciation and amortization of non-current assets	22c	(64,195)	(46,031)	(80,532)
Depreciation and amortization of right-of-use assets	22c	(6,159)	(9,902)	-
Reversal/(Loss allowance) on trade and other receivables		111	(827)	(7,191)
Net impairment losses	22f	(100,776)	(208)	1,735
Other operating income	22e	30,045	42,328	50,589
Results from operating activities		**(84,398)**	**81,125**	**87,039**
Finance income	22g	88	783	433
Finance expenses	22g	(2,301)	(16,364)	(15,913)
Foreign exchange gain/(loss)	22g	2	2,706	(672)
Net Finance income/(expense)		**(2,211)**	(12,875)	**(16,152)**
(Loss)/Profit before income tax		**(86,609)**	**68,250**	**70,887**
Income tax expense	21	(34,777)	(44,775)	12,583
(Loss)/Profit for the period		**(121,386)**	**23,475**	**83,470**
Total comprehensive (loss)/income for the period		**(121,386)**	**23,475**	**83,470**

Notes 1 to 27 are an integral part of the financial statements.

Repsol Oil & Gas Malaysia Limited

STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
FOR THE YEARS ENDED

	USD'000			
	Share capital	Reserves	Retained earnings	Total
At 01.01.2018	**12**	**124,426**	**96,399**	**220,837**
MFRS 9/IFRS 9 adjustment	-	-	(8)	(8)
Total comprehensive income for the period	-	-	83,470	83,470
At 31.12.2018/01.01.2019	**12**	**124,426**	**179,861**	**304,299**
IFRS 16/MFRS 16 adjustment (Note 4.1)	-	-	(434)	(434)
Total comprehensive income for the period	-	-	23,475	23,475
At 31.12.2019/01.01.2020	**12**	**124,426**	**202,902**	**327,340**
Total comprehensive loss for the period	-	-	(121,386)	(121,386)
At 31.12.2020	**12**	**124,426**	**81,516**	**205,954**

The reserves relate to amount of share price in excess of par value of the shares issued in previous years.

Notes 1 to 27 are an integral part of the financial statements.

ACCOUNTANT'S REPORT ON RML (CONT'D)

Repsol Oil & Gas Malaysia Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Repsol Oil & Gas Malaysia Limited

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED

(U.S. dollars)	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Cash flows from Operating Activities			
(Loss)/Profit for the period before tax	(86,609)	68,250	70,887
Adjustments to income:			
Depletion, depreciation and amortization	70,354	55,933	80,532
Net Impairment losses	100,776	208	(1,735)
Interest expense	2,277	3,428	5,257
Accretion expense	24	12,936	10,656
Foreign exchange gain/(loss)	(2)	(2,706)	672
Inventory written off	924	2	736
Write-down/(Reversal) of inventories	744	(33)	1,027
Oil and gas properties written off	1,306	666	1,362
De-recognition of capital lease assets	-	-	1,300
(Write-back)/Loss allowance on trade and other receivables	(111)	827	7,191
Interest income	(36)	(195)	-
Gains on disposal of oil and gas properties	-	(13)	-
Tax penalties	18,739	3,654	-
Change in asset retirement obligation ("ARO") estimates	(223)	(5,772)	(6,679)
Changes in working capital:			
Inventories	*(1,154)*	*1,245*	*(5)*
Trade and other receivables	*28,788*	*(35,993)*	*127,134*
Trade and other payables	*(88,725)*	*(10,110)*	*(71,879)*
Provisions	*(225)*	*150*	*356*
Changes in related parties	*(5,369)*	*3,168*	*(5,723)*
Cash flows generated from operation	41,478	95,645	221,089
Taxes refunded	-	4,934	1,197
Cash flows from Operating Activities	**41,478**	**100,579**	**222,286**
Cash flows from Investing Activities			
Sales proceed from disposal of oil and gas properties	-	13	-
Capital expenditures	(53,171)	(53,611)	(47,683)
Loans to related parties	(15,700)	(38,800)	-
Sinking fund	(6,955)	(17,001)	(15,720)
Repayment of loan from related parties	21,800	20,000	-
Interest received	228	-	-
Cash flows used in Investing Activities	**(53,798)**	**(89,399)**	**(63,403)**
Cash flows from Financing Activities			
Loans from related parties	48,000	24,844	46,030
Repayments of loan to related parties	(48,000)	(33,219)	(126,035)
Interest paid	(92)	(722)	(1,227)
Interest paid on loan from related parties	(193)	(2,739)	-
Lease obligation	(8,190)	(11,742)	(3,380)
Cash flows used in Financing Activities	**(8,475)**	**(23,578)**	**(84,612)**
Net decrease in cash and cash equivalents	**(20,795)**	**(12,398)**	**74,271**
Cash and cash equivalents, beginning of year	68,885	81,283	7,012
Cash and cash equivalents, end of year	**48,090**	**68,885**	**81,283**

Note:
The cash and cash equivalents comprise cash and short-term deposits which are denominated in RM and USD. The short-term deposits have maturity period of less than 30 days (7 days for 2019; nil for 2018). The interest rates for the deposits range from 1.60% to 1.66% (2019: 2.80%)

Notes 1 to 27 are an integral part of the financial statements.

Repsol Oil & Gas Malaysia Limited

NOTES TO THE FINANCIAL STATEMENTS
FOR THE YEARS ENDED 31.12.2020, 31.12.2019, 31.12.2018

1. General Information

This Accountants' Report contains the financial statements of Repsol Oil & Gas Malaysia Limited (hereinafter, "the Company") which comprises the statements of financial position as at December 31, 2020, December 31, 2019 and December 31, 2018, the statements of profit or loss and other comprehensive income, statements of changes in shareholder's equity and statements of cash flows for the financial years ended December 31, 2020, December 31, 2019 and December 31, 2018, and a summary of significant accounting policies and other explanatory notes. The financial statements were prepared by management and approved by the Directors of the Company.

The Company was incorporated on April 6, 1992 under the Companies Act (Bermuda) as International Petroleum Cyrenaica Limited. The Certificate of Incorporation was amended on June 16, 1994 to reflect the change of name of the Company to IPC Malaysia Limited and was amended on May 11, 1998 to reflect the change of name of the Company to Lundin Malaysia Limited. On November 28, 2001 the Company was continued under the Barbados Companies Act Cap 308 (the "Act") and changed its name to Talisman Malaysia Limited. On April 18, 2016 the Articles of the Company were amended to change the name of the Company from Talisman Malaysia Limited to Repsol Oil & Gas Malaysia Limited. The Company was licensed and operated under the International Business Companies Act.

Effective January 1, 2019, the International Business Companies Act Cap. 77 was repealed, and all companies licensed under this act prior to its repeal, are now licensed under the Companies Act Cap. 308. Existing licensees have until 2021 to transition into the regime and have the benefit of grandfathering provisions until they do so under the International Business Companies (Repealed) Act 2018-40. In conjunction with the repeal of the International Business Companies Act Cap. 77, the Income Tax Act Cap. 73 was also amended. The amended Income Tax Act Cap. 73 applies new effective and staggered rates of tax from 1.0% to 5.5% based on a Company's net income. The Company elected to be grandfathered in accordance with International Business Companies (Repeal) Act, 2018-40 of Barbados until June 30, 2021. As a result the tax rates remain at 1.0% to 2.5%.

The Company's ultimate parent company was Talisman Energy Inc ("TEI"). On May 8, 2015, Repsol, S.A. acquired all of the outstanding common shares of TEI and on January 1, 2016, the legal name of TEI was changed to Repsol Oil & Gas Canada Inc. ("ROGCI"). As a result of the acquisition, the ultimate parent is Repsol, S.A. while the intermediate parent is Repsol Exploración, S.A.

The Company's immediate parent was Repsol Oil & Gas Malaysia Holdings Limited ("RMHL"). RMHL amalgamated with Fortuna International Petroleum Corporation on August 31, 2017. As a result of the amalgamation, the Company's immediate parent is Fortuna International Petroleum Corporation, which is registered at 1st Floor, Limegrove Centre, Holetown, St. James, Barbados.

The Company is in the business of exploration, development, production and marketing of crude oil, natural gas and natural gas liquids in Malaysia and Vietnam.

The Company jointly with Repsol Oil & Malaysia (PM3) Limited ("RMPM3"), PETRONAS Carigali Sdn Bhd ("CARIGALI") and Petrovietnam Exploration Production Corporation Limited ("PVEP") are contractor parties under a Production Sharing Contract ("PSC") dated February 16, 1989 with Petroliam Nasional Berhad ("PETRONAS") and Vietnam Oil & Gas Group ("Petrovietnam") for the purpose of exploration, exploitation, winning and obtaining of petroleum resources offshore Block PM-3 CAA. In addition to the PSC, the Company and the Contractor parties are parties to a Joint Operating Agreement ("JOA") for the joint operations of the Block PM-3 CAA. The Company has a participating interest of 26.44% and was appointed as the operator to manage Block PM-3 CAA PSC and JOA. The initial term of the PSC was until February 15, 2017 for crude oil production and December 13, 2018 for natural gas production.

Pursuant to an Addendum to the PSC dated April 16, 2016, the parties had agreed to extend the Block PM-3 CAA PSC and JOA until December 31, 2027. In addition, the participating interest of the Company was also amended under the Addendum to 22.33% ("New Participating Interest") effective February 16, 2017 for the crude oil production and December 14, 2018 for the natural gas production. With regards to the Bunga Kekwa Sub Block in the Block PM-3 CAA, the New Participating Interest for the crude oil production of the aforesaid Sub Block would be applicable from October 29, 2013.

A Unitisation agreement was signed between PETRONAS and Petrovietnam on February 10, 2000 whereby it was agreed that East Bunga Kekwa - Cai Nuoc Field will be developed and exploited by the PM3 CAA Group and Block 46 Group, effective from June 10, 1998. The tract participation interest of the PM3 CAA Group is 75.9508%.

The Company jointly with CARIGALI entered into a PSC dated May 23, 2012 with PETRONAS for the continuing production, further development and improved recovery of crude oil from the Kinabalu fields, offshore Sabah. The PSC was signed for a term of twenty years commencing from December 26, 2012 and expiring on December 25, 2032. The Company also entered into a JOA with CARIGALI for the Kinabalu fields, offshore Sabah. The Company has a participating interest of 60% and was appointed as the operator to manage the Kinabalu field PSC and JOA.

The Company jointly with CARIGALI entered into two separate PSCs dated November 27, 2000 and March 31, 2004, both with PETRONAS for the purpose of exploration, exploitation, winning and obtaining of petroleum resource from Block PM305 and Block PM314, both offshore Peninsular Malaysia respectively. Both PSCs were signed for a term of twenty-nine years commencing from the earlier mentioned dates. The Company also entered into a JOA with CARIGALI for both of the Block PM305 and Block PM314 on the same dates respectively, for the joint operations of the aforesaid Blocks. The Company has a participating interest of 60% in each PSC and was appointed as the operator to manage both Block PM305 and Block PM314 PSCs and JOAs.

The Company had shut in production on September 5, 2019 of the South Angsi, Kuning and Naga Kecil Fields (SAA fields) located in the Block PM305 and Block PM314 PSCs respectively and issued a notice to PETRONAS dated September 30, 2019 to notify of its intention to cease production from the SAA fields on even date. However, PETRONAS in its letter dated April 16, 2020 has instead recognised that the date of cessation of production is at the date of shut in which is September 5, 2019. The Company is currently performing the pre-decommissioning activities.

The Company jointly with CARIGALI entered into two separate PSCs both dated October 26, 2009 with PETRONAS for the purpose of the exploration, exploitation, winning and obtaining of petroleum resource from Block SB309 and Block SB310, offshore Sabah respectively. The PSCs were signed for a term of thirty years each commencing from the earlier mentioned dates. The Company also entered into JOA with CARIGALI for both Block SB309 and Block SB310 on the same dates respectively. The Company has a participating interest of 70% in each of the PSCs and was appointed Operator for both Block SB309 and Block SB310 PSCs and JOAs. Both PSCs are exploration PSCs.

In respect of Block SB310, the Company and its partner PCSB relinquished Block SB310 PSC and JOA on December 31, 2016 and that the outstanding minimum work commitment and remaining training commitment thereunder was transferred to Block SB309 PSC and JOA.

In respect of Block SB309, in light of the completion of the minimum work commitment and minimum financial commitment by the Company during the extended exploration phase of the PSC, CARIGALI was deemed to have elected to bear all its costs, expenses and liabilities in relation to its total participating interest of 30% on March 11, 2019 in accordance with the terms of the Block SB309 JOA.

On December 25, 2019, the Company had opted not to further extend the exploration contract for Block SB309, Block SB309 PSC and JOA expired on December 26, 2019.

The registered office of the Company is 1st Floor, Limegrove Centre, Holetown, St. James, Barbados. The address of the place of business of the Company is Level 33, Menara Citibank, 165, Jalan Ampang, 50450 Kuala Lumpur.

The Company is part of a group of companies under the terms of article 42 of the Code of Commerce, Repsol Group, which ultimate's parent company is Repsol, S.A. Repsol, S.A. is registered at the Madrid Companies Register in sheet no. M-65289. Its registered office is in Madrid, 44 Méndez Álvaro Street.

2. Basis of preparation of the financial statements

The financial statements of the Company for the year ended December 31, 2020, December 31, 2019 and December 31, 2018 have been prepared in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS") which include the Statement of financial position, Statement of Profit or Loss and Other Comprehensive income, Statement of Changes in Shareholder's equity, Statement of Cash Flows and Notes.

The preparation of financial statements in conformity with MFRS/IFRS requires the use of certain critical accounting estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reported period. It also requires the Directors to exercise their judgment in the process of applying the Company's accounting policies. Although these estimates and judgment are based on the directors' best knowledge of current events and actions, actual results may differ. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 5 to the financial statements.

The financial statements reflect only the Company's interest in entitlement under the Production Sharing Contract ("PSC") and share of cost and assets and liabilities under the Joint Operating Agreements.

The items included in the financial statements of the Company are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The functional currency of the Company is United States Dollar ("USD"), which is also the presentation currency.

2.1 Amendments to published standards that are effective

Effective for annual period beginning on/after January 1, 2018

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2018:

- MFRS 9/IFRS 9 'Financial Instruments'
- MFRS 15/IFRS 15 'Revenue from Contracts with Customers'
- IFRIC 22 'Foreign Currency Transactions and Advance Consideration'

The Company has adopted MFRS 9/IFRS 9 and MFRS 15/IFRS 15 for the first time in the 2018 financial year, which resulted in changes in accounting policies. The Company accounting policies on financial instruments and revenue stream are disclosed in details in Notes 3.8, 3.9 and 3.15 respectively. The impact from the adoption of these standards has been disclosed throughout the financial statements and is not material to the Company.

Effective for annual period beginning on/after January 1, 2019

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2019:

- MFRS 16/IFRS 16 'Leases'
- Amendments to MFRS 9/IFRS 9 'Prepayment Features with Negative Compensation'
- Amendments to MFRS 128/IAS 28 'Long-term Interests in Associates and Joint Ventures'
- Amendments to MFRS 119/IAS 19 'Plan Amendment, Curtailment or Settlement'
- IFRIC 23 'Uncertainty over Income Tax Treatments'
- Annual Improvements to MFRSs/IFRSs 2015 - 2017 Cycle

The Company has adopted MFRS 16/IFRS 16 and IFRIC 23 for the first time in the 2019 financial year, which resulted in changes in accounting policies. The information on new accounting policies are disclosed in details in Note 4.

Other than MFRS 16/IFRS 16 and IFRIC 23, the adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

Effective for annual period beginning on/after January 1, 2020

The Company has applied the following amendments to the standards for the first time for the financial year beginning on January 1, 2020:

- The Conceptual Framework for Financial Reporting (Revised 2018)
- Amendments to MFRS 101/IAS 1 and MFRS 108/IAS 8 'Definition of Material'
- Definition of a Business – Amendments to MFRS 3/IFRS 3
- Amendments to MFRS 9/IFRS 9, MFRS 139/IAS 39 and MFRS 7/IFRS 7 'Interest Rate Benchmark Reform'

The adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

2.2 Amendments to published standards that have been issued but not yet effective

Effective for annual period beginning on/after June 1, 2020

- In May 2020, the IASB issued COVID-19-Related Rent Concessions (Amendment to MFRS 16/IFRS 16) that grant an optional exemption for lessees to account for rent concessions occurring as a direct consequence of COVID-19.

  Such concessions might take a variety of forms, including payment holidays and deferral of lease payments. In many cases, this will result in accounting for the concession as a variable lease payment in the period(s) in which the event or condition that triggers the reduced payment occurs.

  The optional exemption permits a lessee to elect not to assess whether a COVID-19-related rent concession is a lease modification. A lessee that makes this election shall account for any change in lease payments resulting from the COVID-19-related rent concession the same way it would account for the change applying MFRS 16/IFRS 16 if the change were not a lease modification.

  The practical expedient applies only to rent concessions occurring as a direct consequence of COVID-19 and only if all of the following conditions are met:
  - The change in lease payments results in revised consideration for the lease that is substantially the same as, or less than, the consideration for the lease immediately preceding the change;
  - Any reduction in lease payments affects only payments originally due on or before June 30, 2021 (a rent concession meets this condition if it results in reduced lease payments on or before June 30, 2021 and increased lease payments that extend beyond June 30, 2021); and
  - There is no substantive change to other terms and conditions of the lease.

  The amendments shall be applied retrospectively. The adoption of the above amendments will not have significant impact on the Company's financial statements.

Effective for annual period beginning on/after January 1, 2022

- The amendments to MFRS 116/IAS 16 'Property, Plant and Equipment - Proceeds before Intended Use' prohibit an entity deducting from the cost of an item of property, plant and equipment ("PPE") the proceeds received from selling items produced by the property, plant and equipment before that asset is ready for its intended use, i.e. proceeds while bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Consequently, an entity recognises such sales proceeds and related costs in profit or loss. (Effective date 1 January 2022)

  The amendments also clarify the meaning of 'testing whether an asset is functioning properly'. MFRS 116/IAS 16 now specifies this as assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes.

  If not presented separately in the statement of comprehensive income, the financial statements shall disclose the amounts of proceeds and cost included in profit or loss that relate to items produced that are not an output of the entity's ordinary activities, and which line item(s) in the statement of comprehensive income include(s) such proceeds and cost.

  The amendments are applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments.

The entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the beginning of that earliest period presented.

- The amendments to MFRS 137/IAS 37 'Onerous Contracts – Cost of Fulfilling a Contract' specify that the 'cost of fulfilling' a contract comprises the 'costs that relate directly to the contract'. Costs that relate directly to a contract consist of both the incremental costs of fulfilling that contract, as well as an allocation of other costs that relate directly to fulfilling contracts. The amendments also clarify that before recognising a separate provision for an onerous contract, impairment loss that has occurred on assets used in fulfilling the contract should be recognised. (Effective date 1 January 2022)

  The amendments shall be applied retrospectively and apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments. Comparatives are not restated.

  Instead, the entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings or other component of equity, as appropriate, at the date of initial application.

- Annual Improvements to MFRS/IFRS Standards 2018–2020 (Effective date 1 January 2022)

  The following improvements were finalised in May 2020:

  - MFRS 9/IFRS 9 Financial Instruments – clarifies which fees should be included in the 10% test for derecognition of financial liabilities.

  - IFRS 16/MFRS 116 Leases – amendment of illustrative example 13 to remove the illustration of payments from the lessor relating to leasehold improvements, to remove any confusion about the treatment of lease incentives.

  - MFRS 1/IFRS 1 First-time Adoption of International Financial Reporting Standards – allows entities that have measured their assets and liabilities at carrying amounts recorded in their parent's books to also measure any cumulative translation differences using the amounts reported by the parent. This amendment will also apply to associates and joint ventures that have taken the same MFRS 1/IFRS 1 exemption.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

<u>Effective for annual period beginning on/after January 1, 2023</u>

- Amendments to MFRS 101/IAS 1 - Disclosure of accounting policy information - require entities to disclose their material rather than their significant accounting policies (Effective date 1 January 2023)

- Amendments to MFRS 108/IAS 8 - Definition of accounting estimates - clarifies how companies should distinguish changes in accounting policies from changes in accounting estimates (Effective date 1 January 2023)

- Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to MFRS 112/ IAS12) - require companies to recognise deferred tax on transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences (Effective date 1 January 2023)

- The amendments to MFRS 101/IAS 1 'Classification of Liabilities as Current or Non-current' affect only the presentation of liabilities as current or non-current in the statement of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items (Effective date 1 January 2023)

  The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants are complied with at the end of the reporting period, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

3. Significant accounting policies

3.1 Basis of accounting

The financial statements of the Company have been prepared under the historical cost convention unless otherwise stated in the accounting policies mentioned below. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

3.2 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Company takes into account the characteristics of the asset or liability if market participants would take those characteristic into account when pricing the asset or a liability at the measurement date. Fair value for measurement and/or disclosure purposes in these financial statements is determined on such a basis, except for any share-based payment transactions that are within the scope of MFRS 2/IFRS 2, leasing transactions that are within the scope of MFRS16/MFRS117/IFRS16/IAS 17, and measurements that have some similarities to fair value but are no fair value, such as net realisable value in MFRS 102/IAS 2 or value-in-use in MFRS 136/IAS 36.

In addition, for financial reporting purposes, fair value measurements are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value measurements are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

3.3 Classification of assets and liabilities into current and non-current

In the accompanying statement of financial position, assets and liabilities maturing within twelve months are classified as current items and those maturing in more than twelve months are classified as non-current items.

3.4 Intangible assets

Intangible assets comprise implementation cost of the SAP Project One and expenditure on the exploration for and evaluation of oil and gas resources directly associated with an exploration well, including license acquisition and drilling costs, are initially capitalised as intangible assets until the results have been evaluated. During the exploration and evaluation phase, these costs are not amortized, although they are tested for impairment at least once a year and whenever indications of impairment are detected. Once the exploration and evaluation phase is completed, if no reserves are found, the amounts previously capitalized are recognized as an expense in the statement of profit or loss and other comprehensive income. If the exploration work does yield positive results, giving rise to commercially exploitable wells, costs are reclassified to "*Oil and gas properties*" at their carrying amount when this determination is made.

Exploration costs other than G&G costs ("Exploration rights and geology and geophysical costs"), excluding the costs of drilling exploration wells and exploration licenses, are recognized as an expense in the statement of profit or loss and other comprehensive income when incurred.

3.5 Property, Plant and Equipment

The Company uses the cost model by which items of property, plant and equipment are measured initially at acquisition cost.

The cost of property, plant and equipment includes their acquisition cost, all the costs directly related to the location of assets and all the costs to make them operational.

Additionally, if applicable, the cost of property, plant and equipment includes the present value of the expected disbursements necessary for any costs of dismantling and removing the item or restoring the site on which it is located, when such obligations are incurred under certain conditions. Subsequent changes to the measurement of the dismantling obligations and related liabilities resulting from changes in the estimated cash flows and/or in the discount rate are added to or deducted from the asset's carrying amount in the period in which they are incurred, except where the lower corrected value of the liability is greater than the carrying amount of the associated asset, in which case the surplus is recognized in the statement of profit or loss and other comprehensive income.

Borrowing costs that are directly attributable to the acquisition or construction of assets that require more than one year to be ready for use are capitalized as part of the cost of these assets, in accordance with the limits established in the applicable accounting rules.

Personnel expenses and other operating expenses directly attributable to the construction of the asset are also capitalized.

The costs of expansion, modernization or improvements leading to increased productivity, capacity or efficiency or to a lengthening of the useful lives of the assets are capitalized, as long as the general capitalization criteria are met.

Repair, upkeep and maintenance expenses are recognized in the statement of profit or loss and other comprehensive income as incurred. Furthermore, certain facilities require periodic reviews. In this respect, the assets subject to replacement are recognized specifically and are depreciated over the average term remaining until the next repairs are carried out.

Property, plant and equipment, other than those items relating to oil and gas exploration and production activities, are depreciated using the straight-line method on the basis of the acquisition cost of the assets less their estimated residual value, over the years of estimated useful life of the assets.

Depreciation of these assets starts when the assets become available for use.

Recognition of oil and gas exploration and production assets

The Company recognizes hydrocarbon exploration and production operations using accounting polices mostly based on the "successful efforts" method. Under this method, the various costs incurred are treated as follows for accounting purposes:

i. The costs incurred in the acquisition of new interests in areas with proved and unproved reserves are capitalized as incurred under "*Oil and gas properties*" item of property, plant and equipment.

ii. The costs of acquiring exploration permit and the geological and geophysical (G&G) costs incurred during the exploration phase are capitalized in intangible assets. They are not amortized during the exploration and evaluation phase and they are tested for impairment at least once a year and, in any case, when there is an indication that they may have become impaired, In accordance with the indicators of MFRS 6/IFRS 6 Exploration for and evaluation of mineral resources. Once the exploration and evaluation phase is over, if no economically viable reserves are found, the amounts capitalized are recognized as an expense in the statement of profit or loss and other comprehensive income.

iii. *Exploratory drilling costs*, including those relating to stratigraphic exploration wells, are capitalised as "*Evaluation and Exploration Assets*" in property, plant and equipment until it is determined whether proved reserves justifying their commercial development have been found. If no reserves are found, the capitalized drilling costs are registered in the statement of profit or loss and other comprehensive income. In the event that reserves are found but remain under evaluation for their classification as proved, their recognition depends on the following:

   - If additional investments are required prior to the start of production, they continue to be capitalized whilst the following conditions are met: (i) the amount of proved reserves found justifies the completion of a productive well if the required investment is carried out, and; (ii) satisfactory progress has been made in the evaluation of reserves and the operational viability of the project. If any of these conditions fail to be met, they are treated as impaired, and are expensed in the statement of profit or loss and other comprehensive income.

   - In all other cases, if there is no commitment to carry out significant activities to evaluate reserves or develop the project within a reasonable period after well drilling has been completed, or if activities have been halted, they must be recorded as an expense in the statement of profit or loss and other comprehensive income.

   - Costs incurred in exploratory drilling work that has yielded a commercially exploitable reserve are reclassified to "*Oil and gas properties*" under property, plant and equipment at their carrying amount.

iv. *Exploration costs* other than geological and geophysical costs, excluding the costs of drilling exploration wells and exploration licenses, are recognized as an expense in statement of profit or loss and other comprehensive income when incurred.

v. *Development expenditure* incurred in developing proved reserves and in processing and storing oil and gas (including costs incurred in drilling relating to productive wells and dry wells under development, oil rigs, recovery improvement systems, etc.) are recognized as assets under "*Oil and gas properties*".

vi. *Future field abandonment and dismantling costs* (environmental, safety, etc.) are estimated, on a field-by-field basis, and are capitalized at their present value when they are initially recognized under "*Oil and gas properties*" in assets in the statement of financial position. This capitalization is recorded against the caption "*Asset retirement obligation*" (see Note 18).

The costs capitalized as described above are depreciated as follows:

i. Investments in the acquisition of proven and probable reserves and common facilities are depreciated over the estimated commercial life of the field on the basis of the production for the period as a proportion of the proven and probable reserves.

ii. The costs incurred in surveys for the development and extraction of hydrocarbon reserves are depreciated over the estimated commercial life of the oil field on the basis of the relationship between the production of the period and the total of the most probable proved reserves of the field.

iii. Investments carried out in fields that are in the development or exploitation phase are not depreciated. These investments are tested for impairment at least once a year and whenever indications of impairment are detected.

The changes in estimated reserves are considered on a prospective basis in calculating depreciation.

3.6 Impairment of property, plant and equipment, intangible assets

In order to ascertain whether its assets have become impaired, the Company compares their carrying amount with their recoverable amount at least annually and whenever there are indications that the assets might have become impaired. Recoverable amount is the higher of fair value less costs to sell and value in use. If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized as an expense in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined in case no impairment loss had been recognized for the asset in prior years.

3.7 Sinking funds

The Company contribute to a separate fund established to help fund decommissioning and environmental obligations. The Company recognises its interest in the fund separately from the liability to pay the decommissioning costs. Offsetting is not appropriate unless the Company is not liable to pay decommissioning costs even if the funds fails to pay. The Company does not have control, joint control or significant influence over the fund and therefore, the right to receive assets of the funds are accounted for as a reimbursement of the entity's decommissioning obligation, at the lower of the amount of the decommissioning obligation and the Company's share of the fair value of net assets of the fund.

3.8 Financial assets

Classification

The Company classifies its financial assets at the time it is initially recognised and is subsequently measured at either amortised costs, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL").

The classification of financial asset at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing the financial assets. For assets measured at fair value, gains and losses will either be recorded in profit or loss or other comprehensive income ("OCI"). For investments in equity instruments that are not held for trading, this will depend on whether the Company has made an irrevocable election at the time of initial recognition to account for the equity investment at FVOCI.

The Company reclassifies debt investments when and only when its business model for managing those assets change.

Recognition and initial measurement

At initial recognition, with the exception of trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at FVTPL, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are expensed in profit or loss. Trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient is measured at the transaction price as determined under MFRS 15/IFRS 15.

Financial assets with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

Subsequent measurement

Subsequent measurement of debt instruments depends on the Company's business model for managing the asset and the cash flow characteristics of the asset. There are three measurement categories into which the Company classifies its debt instruments:

a) Debt instruments

i. Amortised cost

Assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortised cost. Interest income from these financial assets is included in finance income using the effective interest rate method. Any gain or loss arising on derecognition of the Company's financial assets are recognised directly in profit or loss and presented in other operating gains/(losses). Impairment losses are presented as separate line item in the statement of profit or loss and other comprehensive income.

ii. FVTPL

Assets that do not meet the criteria for amortised cost or FVOCI are measured at FVTPL. A gain or loss on a debt investment that is subsequently measured at FVTPL is recognised in profit or loss and presented net within other operating gains/(losses) in the period in which it arises.

b) Equity instrument

FVOCI

Assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Movements in the carrying amount are taken through OCI, except for the recognition of impairment gains or losses, interest revenue and foreign exchange gains and losses which are recognised in profit or loss. When the financial asset is derecognised, the cumulative gain or loss previously recognised in OCI is reclassified from equity to profit or loss and recognised in other operating gains/(losses). Interest income from these financial assets is included in finance income using the effective interest rate method. Foreign exchange gains and losses and impairment expenses are presented in other operating gains/(losses). When it is deemed to be material in nature, the impairment expenses shall be presented as separate line item in the statement of profit or loss and other comprehensive income.

Impairment of financial assets

From January 1, 2018, the Company assesses on a forward looking basis the expected credit losses ("ECL") associated with its debt instruments carried at amortised cost. The amount of the expected credit losses is updated at the end of each reporting period to reflect changes in credit risk since initial recognition of the respective financial instrument.

The expected credit losses on these financial assets are estimated using a provision matrix based on the Company's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. For all other financial instruments, the Company recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the Company measures the loss allowance for that financial instrument at an amount equal to 12 month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12 month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

The Company applies the MFRS 9/IFRS 9 simplified approach to measure ECL which uses a lifetime ECL for all trade receivables, see Note 5.2.5 to the financial statements for further details.

Significant increase in credit risk

The Company considers the probability of default upon initial recognition of asset and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. To assess whether there is a significant increase in credit risk, the Company compares the risk of a default occurring on the asset as at the reporting date with the risk of default as at the date of initial recognition. It considers available reasonable and supportable forward looking information that includes historical default rate, internal and external credit rating (as applicable), actual or expected changes in economic and regulatory environment that are expected to cause a significant change to the debtor's ability to meet its obligations.

A significant increase in credit risk is presumed if a debtor become inactive, indication of consistent delay in making contractual payments that are long past due with history of default or the debtor is expected to/or is experiencing significant financial difficulties and cash flow problems.

Derecognition of financial assets

Financial assets are derecognised when the contractual rights to receive cash flows from the financial assets have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Any gain or loss arising on derecognition is recognised directly in profit or loss and presented in other gains/(losses) together with foreign exchange gains and losses.

3.9 Financial liabilities

Classifications

Financial liabilities are classified according to the substance of the contractual arrangements entered into and the definitions of a financial liability. Management determines the classification of financial liabilities at initial recognition.

Financial liabilities are recognised in the statements of financial position when, and only when, the Company become a party to the contractual provisions of the financial instrument. The Company classifies all its financial liabilities as other financial liabilities.

Recognition and initial measurement

Trade and other payables are recognised initially at fair value net directly attributable transaction costs and subsequently measured at amortised cost using the effective interest method.

Loans and borrowings are recognised initially at fair value, net of transaction costs incurred and subsequently measured at amortised cost using the effective interest method. Borrowings are classified as current liabilities unless the Company have an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

Derecognition of financial liabilities

A financial liability is derecognised when the obligation under the liability is extinguished. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in the statements of comprehensive income.

3.10 Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when there is a legally enforceable right to offset the recognised amounts and there is an intention to settle on a net basis, or realise the asset and settle the liability simultaneously. The legally enforceable rights must not be contingent on future events and must be enforceable in the normal course of business and in the event of default, insolvency or bankruptcy.

3.11 Cash and cash equivalents

The Company classifies under "*Cash and cash equivalents*" in the statement of financial position liquid financial assets, deposits or financial assets that can be converted into a known amount of cash three months from initiation to maturity and that are subject to an insignificant risk of changes in value.

3.12 Trade and other receivables

Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, where they are recognised at fair value plus transaction costs. Other receivables are recognised initially at fair value plus transaction costs. The impairment policy for trade receivables is in accordance with that for impairment of financial assets as described in Note 3.8 to the financial statements.

3.13 Provisions and contingent liabilities

In accordance with prevailing accounting standards, the Company makes a distinction between:

a) Provisions: present obligations, either legal or assumed by the Company, arising from past events, the settlement of which is probable to give rise to an outflow of resources the amount and timing of which are uncertain; and

b) Contingent liabilities: possible obligations that arise from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more future events not wholly within the control of the Company, or present obligations arising from past events, the amount of which cannot be measured with sufficient reliability or whose cancellation is not likely to give rise to an outflow of resources embodying future economic benefits.

These provisions are recognized when the liability or obligation giving rise to the indemnity or payment arises, to the extent that its amount can be reliably estimated and it is probable that the commitment will have to be settled.

Contingent liabilities are not recognized as provisions in the financial statements. Notwithstanding the above, whenever it is deemed as non-remote that settlement of such a liability will give rise to an outflow of resources, the existence of these liabilities is disclosed.

3.14 Asset Retirement Obligation ("ARO")

The fair values of the statutory, contractual or legal obligations associated with the retirement and reclamation of tangible long-lived assets are recorded when incurred and when a reasonable estimate of this amount can be made, with a corresponding increase to the carrying amount of the related assets. The increase to capitalised costs is amortised to profit and loss on a basis consistent with the depreciation, depletion and amortisation of the underlying assets. Subsequent changes in the estimated fair value of the ARO are capitalised and amortised over the remaining useful of the underlying asset.

The ARO liabilities are carried on the statement of financial position at their discounted present value and are accreted over time for the change in their present value, with this accretion charge recognised in profit and loss.

Actual expenditure incurred are charged against the accumulated obligation. Any difference between the recorded ARO and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

3.15 Revenue and expenses recognition

Revenue associated with the sale of crude oil and natural gas are recognised when control of the goods has transferred, being at the point the crude oil and natural gas exiting from the Company's storage tanks into the customer's storage tank.

Revenue from the sale of crude oil and natural gas are recognised based on the price in the agreement, that is the market price. Each of the field produces its own oil into distinctive tanks, and hence the benefit is derived from the lifted oil of the specific tanks distinctively and each lifting of entitled oil is a separate and distinctive performance obligation on its own as the benefits are directly derived from selling this.

Crude oil produced and sold by the Company below or above its working interest share in the related resource properties, results in production under-lifting or over-lifting.

The Company has adopted the entitlement method in measuring the under-lifting and over-lifting whereby they were measured at the fair value. Under-lifting is recorded as part of the *"Trade and other receivables"* in the statement of financial position and *"Change in underlift"* in the statement of profit and loss and other comprehensive income. Over-lifting is recorded as part of the *"Trade and other payables"* in the statement of financial position and presented as *"Supplies"* in the statement of profit or loss and other comprehensive income, along with purchases made during the year.

Under-lifting is reversed when the crude oil is lifted and sold, with the sales proceeds recorded as revenue and the cost of the inventory expensed. Over-lifting is reversed when sufficient volumes are produced to make up the overlifted volume.

The Company's operations are governed by the PSC. Under the PSC, revenues are derived from cost recovery oil and gas and profit oil and gas. Generally, cost recovery oil and gas allows the Company to recover its capital and production costs and, as appropriate, the costs carried by the Company on behalf of relevant national oil company from production. Profit oil and gas is allocated to the national oil company and contract parties in accordance with the terms of the respective PSCs.

Interest income is accrued on a time proportion basis, by reference to the principal outstanding and the effective interest rate applicable.

An expense is recognized when there is a decrease of economic benefits associated to a reduction of an asset, or an increase in a liability, whichever can be measured reliably.

3.16 Financing costs

Financing costs comprise interest payable on borrowings and any accretion in provision due to the passage of time.

3.17 Employee benefits

a) Short-term benefits

Wages, salaries, bonuses and social security contributions are recognised as an expense in the year in which the associated services are rendered by employees of the Company. Short-term accumulating compensated absences such as paid annual leave are recognised when services are rendered by employees that increase their entitlement to future compensated absences, and short term non-accumulating compensated absences such as sick leave are recognised when the absence occur.

b) Defined contribution plan

As required by law, companies in Malaysia make contributions to the state pension scheme, the Employees Provident Fund ("EPF"). Such contributions are recognised as an expense in profit or loss as incurred.

3.18 Income tax

The Company recognizes in the statement of profit or loss and other comprehensive income for the year the accrued tax on the Company's income, which is calculated taking into account the differences between the timing of recognition for accounting purposes and tax purposes of the transactions and other events in the current year recognized in the financial statements, giving rise to temporary differences and, therefore, to the recognition of certain deferred tax assets and liabilities in the statement of financial position. These amounts are recognized by applying to the temporary differences the tax rate that is expected to apply in the period when the asset is realized, or the liability is settled.

Taxation on profit for the year is calculated at the current tax rate based on the estimated chargeable income for the year computed under the Petroleum (Income Tax) Act, 1967 ("PITA"), Income Tax Act, 1967 and Income Tax Act Cap. 73.

Deferred tax liabilities are recognized for all taxable temporary differences, unless the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets recognized for temporary differences and other deferred tax assets (tax losses and tax deductions carry forwards) are recognized when it is considered probable that the Company will have sufficient taxable profits in the future against which the deferred tax asset can be utilized. Deferred tax assets relating to the carry forward of unused tax losses are recognised to the extent that it is probable that future taxable profit will be earned against which the unused tax losses can be utilised.

The accrued income tax expense includes both the deferred income tax expense and the current income tax expense, which is taken to be the amount payable (or refundable) in relation to the taxable net income for the year (see Note 21).

"*Income tax expense*" in the statement of profit or loss and other comprehensive income includes both the accrued income tax expense and the net provisions recognized in the year for uncertain tax position, insofar as the latter relate to income tax.

Current and deferred taxes are recognized outside statement of profit or loss and other comprehensive income if they are related to items that are recognized outside the statement of profit or loss and other comprehensive income. Those entries related to items recognized under "Adjustments for changes in value" are recognized under that heading and those recognized directly in equity are recognized within the equity.

3.19 Foreign Currency

The Company's functional and presentation currency is United States dollars. Transactions in currencies other than the functional currency are deemed to be 'foreign currency transactions' and are translated to the functional currency by applying the exchange rates prevailing at the date of the transaction. At each year end, the foreign currency monetary items on the statement of financial position are measured applying the exchange rate prevailing at that date and the exchange rate differences arising from such measurement are recorded as *"foreign exchange gain/(loss)"* within *"Financial income/(expenses)"* in the statement of profit or loss and other comprehensive income in the year incurred.

3.20 Leases

A lease is an agreement whereby the lessor conveys to the lessee in return for a payment, or series of payments, the right to use an asset for an agreed period of time.

a) Leases in which the Company is a lessee

From January 1, 2019, leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company (i.e. the commencement date).

Lease terms

In determining the lease term, the Company considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not to be terminated).

The Company reassess the lease term upon the occurrence of a significant event or change in circumstances that is within the control of the Company and affects whether the Company is reasonably certain to exercise an option not previously included in the determination of lease term, or not to exercise an option previously included in the determination of lease term. A revision in lease term results in re-measurement of the lease liabilities.

ROU assets

ROU assets are initially measured at cost comprising the following:

- The amount of the initial measurement of lease liability;
- Any lease payments made at or before the commencement date less any lease incentive received;
- Any initial direct costs; and
- Decommissioning or restoration costs.

Upon lease commencement, the Company measures the ROU asset using a cost model. ROU assets are depreciated over the lease term on a straight-line basis.

Lease liabilities

Lease liabilities are initially measured at the present value of the lease payments that are not paid at that date. The lease payments include the following:

- Fixed payments (including in-substance fixed payments), less any lease incentive receivable;
- The exercise price of an extension options if the Company is reasonably certain to exercise that option; and
- Payments of penalties for terminating the lease, if the lease term reflects the Company exercising that option.

Lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be readily determined for leases in the Company, the Company's incremental borrowing is used. This is the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the ROU in a similar economic environment with similar term, security and conditions.

Lease payments are allocated between principal and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

The Company presents the lease liabilities as a separate line item in the statement of financial position. Interest expense on the lease liability is presented within the finance cost in the statement of profit or loss and other comprehensive income.

Reassessment of lease liabilities

The Company is exposed to potential cash flows change if there is a change in lease term due to the Company exercises an extension or termination option, which are not included in the lease liability until the Company is reasonably certain to exercise the option.

When the option is exercised, the lease liabilities are remeasured by discounting the revised lease payments using revised discount rate.

Short-term leases and leases of low-value assets

Short-term leases are leases with a lease term of 12 months or less. Low-value assets comprise IT equipment, small items of office furniture and vehicles. Payment associated with short-terms lease of equipment, vehicles and vessels and all leases of low-value assets are recognised on a straight-line basis as an expense in the statement of profit or loss and other comprehensive income.

Until December 31, 2018, a lease is recognised as a finance lease if it transfers substantially to the Company all the risks and rewards incident to ownership. All leases that do not transfer substantially all the risk and rewards are classified as operating leases.

Finance leases

Assets acquired by way of finance leases are stated at an amount equal to the lower of their fair values and the present value of the minimum lease payments at the inception of the leases, less accumulated depreciation and impairment losses. The corresponding liability is included in the statement of financial position as part of "*Trade and other payables*" for current portion and "*Long-term lease obligation*" for non-current portion. In calculating the present value of the minimum lease payments, the discount factor used is the interest rate implicit in the lease, when it is practicable to determine; otherwise, the Company's incremental borrowing rate is used.

Lease payments are apportioned between the finance charges and the reduction of the outstanding liability. Finance costs, which represent the difference between the total leasing commitments and the fair value of the assets acquired, are recognised as finance expenses in the statement of comprehensive income over the term of the relevant lease so as to produce a constant periodic rate of charge on the remaining balance of the obligations for each accounting period.

The depreciation policy for capital lease is in accordance with that for depletion, depreciation and amortisation as described in Note 3.5.

Operating leases

Leases where substantially all the rewards and risks of ownership of assets remain with the lessor are accounted for as operating leases. Rental on operating leases are charged to profit or loss on a straight line basis in the financial year in which they are incurred.

3.21 Inventories

Inventories are valued at the lower of cost less provision for obsolescence and net realisable value. The cost is calculated as average cost, and includes the acquisition costs after deduction of any discounts, rebates or other similar items, such as interest incorporated into the nominal amount, plus any additional costs incurred to bring the goods to a saleable condition, such as transport, import duties, insurance and other costs directly attributable to the acquisition of inventories. The inventories of the Company are the Company's share of purchased materials held under the joint operations agreements for utilisation in conducting the affairs of the joint operations.

The Company carries out annual material review of inventories at the end of the year, recording the appropriate value correction with a charge to results when inventories are obsolete and no foreseeable future usage. When the circumstances that previously caused the value correction cease to exist, the amount is reversed.

3.22 Transactions with related parties

The Company performs all its operations with related parties at agreed terms and prices which is why management considers that there are no significant risks from this aspect from which future liabilities may arise.

3.23 Joint Operation Agreements

The Company recognises its share of jointly controlled assets and jointly incurred liabilities on the basis of the percentage of ownership, as well as jointly controlled assets and liabilities incurred as a result of the joint operation agreements.

The Company recognises the proportion of income generated and expenses incurred under the joint operation agreement in the statement of profit or loss and other comprehensive income, in addition to the expenses incurred in relation to the interest in the joint operation.

4. New accounting policies

4.1 MFRS 16/IFRS 16 Leases

The Company has applied MFRS 16/IFRS 16 with the date of initial application of January 1, 2019 by applying the simplified retrospective transition method.

Under the simplified retrospective transition method, the 2018 comparative information was not restated and cumulative effects of initial application of MFRS 16/IFRS 16 where the Company is lessee were recognised as an adjustment to the opening balance of retained earnings as at January 1, 2019. The comparative information continued to be reported under the previous accounting policies governed under MFRS 117/IAS 17 'Leases' and IFRIC 4 'Determining whether an Arrangement Contains a Lease'.

In addition, the Company has elected not to reassess whether a contract is, or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date, the Company relies on its assessment made applying MFRS 117/IAS 17 and IFRIC 4.

The new accounting policies are disclosed in Note 3.20.

On adoption of MFRS 16/IFRS 16, the Company recognised lease liabilities in relation to leases which had been previously classified as 'operating leases' under the principle of MFRS 117/IAS 17 Lease. These liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate as of January 1, 2019.

The associated right-of-use ("ROU") assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognised in the statement of financial position as at December 31, 2018.

In applying MFRS 16/IFRS 16 for the first time, the Company has applied the following practical expedients permitted by the standard to leases previously classified as operating leases under MFRS 117/IAS 17:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- reliance on previous assessments on whether leases are onerous;
- the accounting for operating leases with a remaining lease term of less than 12 months as at January 1, 2019 as short-term leases;
- the exclusion of initial direct costs for the measurement of the ROU asset at the DIA; and
- the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

For leases previously classified as finance leases and presented as part of 'property, plant and equipment', the Company recognised the carrying amount of the lease assets and lease liability immediately before transition as the carrying amount of the ROU asset and the lease obligation at the date of initial application ("DIA").

Measurement of lease obligation on January 1, 2019

The weighted average lessee's incremental borrowing rate applied to the lease liabilities on January 1, 2019 was 5.12% per annum for USD contracts and 9.60% per annum for MYR contracts.

The reconciliation between operating lease commitments disclosed applying MFRS 117/IAS 17 at December 31, 2018 to the lease liabilities recognised at January 1, 2019 is as follows:

	USD'000
Operating lease commitments disclosed as at December 31, 2018	26,729
Discounted using the lessee's incremental borrowing rate of at the DIA	22,330
Add:	
Finance lease liabilities recognised as at December 31, 2018	24,181
Lease obligation recognised as at January 1, 2019	**46,511**
Of which are:	
Current lease obligation	10,037
Non-current lease obligation	36,474
	46,511

ACCOUNTANT'S REPORT ON RML (CONT'D)

Repsol Oil & Gas Malaysia Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

The effect of the changes in the accounting policies on the line items are as follows:

	USD'000 As previously report as at December 31, 2018	USD'000 MFRS 16/IFRS 16 adjustment	USD'000 As re-measured as at January 1, 2019
Statement of financial position (extract) As at January 1, 2019			
Property, plant and equipment	351,876	(19,605)	332,271
Right-of-use assets	-	41,501	41,501
Retained earnings	(179,861)	434	(179,427)
Long-term lease obligation	(20,540)	(15,934)	(36,474)
Trade and other payables	(138,210)	(6,396)	(144,606)

4.2 IFRIC 23 Uncertainty over income tax treatments

The Company has applied the IFRIC 23 that clarifies the accounting for uncertainties in income taxes, effective for annual periods beginning on or after 1 January 2019.

The interpretation is to be applied to the determination of taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates, when there is uncertainty over income tax treatments under MFRS 112/IAS 12.

An entity has to consider whether it is probable that the relevant authority will accept each tax treatment, or group of tax treatments, that it used or plans to use in its income tax filing.

If the entity concludes that it is probable that a particular tax treatment is accepted, the entity has to determine taxable profit (tax loss), tax bases, unused tax losses, unused tax credits or tax rates consistently with the tax treatment included in its income tax filings. If the entity concludes that it is not probable that a particular tax treatment is accepted, the entity has to use the most likely amount or the expected value of the tax treatment when determining taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates. The decision should be based on which method provides better predictions of the resolution of the uncertainty.

During the financial year 2019, a provision of $11,862 thousand is made for uncertain tax position of the Company in relation to the Petroleum (Income Tax) Act, 1967 ("PITA") on the deductibility of certain expenses.

The amount of tax provision is measured based on "most likely amount" method. The PITA provision is made in accordance to the Notice of Additional Assessment ("NoAA") received from Inland Revenue Broad ("IRB") of Malasya for Year Assessment ("YA") 2014.

Due to the uncertainty associated with such tax items, there is a possibility that, on conclusion of open tax matters at a future date, the final outcome may differ significantly.

5. Critical accounting judgments and key sources of estimation uncertainty

5.1 Critical judgements in applying the Company's accounting policies

In the process of applying the Company's accounting policies, which are described in Note 3 above, management is of the opinion that there are no instances of application of judgement which are expected to have a significant effect on the amounts recognised in the financial statements.

5.2 Key sources of estimation uncertainty

The information included in these financial statements is the responsibility of the management of the Company.

In the financial statements for the year 2020, 2019, and 2018 on occasions estimations made by the management of the Company have been used to evaluate some of the assets, liabilities, income, expenses and commitments that are recorded in the accounts. Basically, those estimations, made according to the best information available, relate to:

- Assessment of potential impairment losses on certain assets
- Estimation of crude oil and gas reserves and resources
- Provisions for litigation, dismantling and other contingencies
- Calculation of income tax, tax credit and deferred tax assets
- Calculation of expected credit loss
- Extension and termination options of leases
- Allowance for inventories obsolescence

5.2.1 Assessment of potential impairment losses on certain assets

In order to ascertain whether its assets have become impaired, the Company compares the carrying amount with the recoverable amount at least annually and whenever there are indications that an asset might have become impaired ("impairment test"). If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

On the occurrence of new events, or changes in existing circumstances, which prove that an impairment loss recognized on a prior date no longer exists or has decreased, a new estimate of the recoverable value of the corresponding asset is developed, to determine whether it is appropriate to reverse the impairment losses recognized in previous periods.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized for the asset in prior years.

For the "impairment test", assets are grouped into cash-generating units (CGUs), to the extent that such assets, when individually considered, do not generate cash inflows that are independent of the cash inflows from other assets or CGUs. The grouping of assets into the various CGUs requires the use of professional judgments and the determination, among other criteria, of the business segments and geographic areas in which the Company operates. In the upstream segment, each CGU corresponds to one of the various contractual exploration areas widely known as "blocks" exceptionally, if the cash flows generated by more than one block are mutually interdependent, those blocks will be grouped into a single CGU.

The recoverable amount is the higher of fair value less costs of sale and value in use.

The methodology used by the Company to estimate the recoverable amount of assets is, in general, the value in use calculated by discounting to present value the future cash flows after tax expected to be derived from the operation of these assets.

The cash flow projections are based on the best available estimates of the CGUs' income and expenses using sector forecasts, prior results and the outlook for the business's performance and market's development:

- Macroeconomic variables are those used in the preparation of the budgets. The macroeconomic framework for the countries in which the Group operates takes into consideration variables such as inflation, GDP, exchange rate, etc. and is prepared on the basis of the content of internal reports that use in-house estimates, based on updated external information of relevance (forecasts prepared by consultants and specialized entities).

- The oil and natural gas price paths used for the impairment test are our own estimates, although they are consistent or in line with the view of prices established by the various international benchmark agencies, including the International Energy Agency ("IEA"). The paths are developed on the basis of available macroeconomic, financial and market information and the forecasts provided by analysts and they consider scenarios for the energy transition and decarbonisation of the economy that are consistent with the commitments assumed to achieve the objectives of the Paris Climate Summit.

In particular, crude oil and gas prices are calculated by analysing key market variables and their foreseeable trend, including our own forecasts of the balance of supply and demand of energy and prices. The longer-term vision is also explained by monitoring other variables such as: the decline, the current CAPEX, the financial sustainability of companies in the sector to certain price environments, and the dynamics in OPEC countries in terms of fiscal sustainability. Econometric models of prices are made with all these elements, which are compared with both public and private external forecasts.

i. To estimate near-term price trends, we basically use forecast reports produced by a selection of, investment banks, macro consultants and international benchmark agencies are taken into account.

ii. The sources that present a sufficiently detailed analysis of long-term forecasts are the macro consultants and benchmark agencies (IEA and EIA), which also carry out detailed studies of supply, demand and price forecasts under different scenarios.

The assumptions for the main price references for 2018 are as follows:

	2019	2020	2021	2022	2023	2024	2025	2026	2027 – 2032
Brent ($/ barrel)	65	70	75	81	86	89	92	94	97

The assumptions for the main price references for 2019 are as follows:

	2020	2021	2022	2023	2024	2025 – 2029	2030 - 2031	2032
Brent ($/ barrel)	65	69	70	71	72	74	81	87

In 2020, in view of the situation in the commodity markets and in particular the social and economic consequences of the COVID-19 pandemic and the foreseeable development of the energy transition, the Group reviewed its expectations of future oil and gas prices, modifying the price paths defined at the end of 2019 to bring them into line with the new scenario.

It should be noted that these estimates were made in an environment of high uncertainty, marked by the scenarios of emerging from the COVID-19 crisis, by the dynamics of the energy transition and decarbonisation of the economy and, in short, by their possible impacts on the Oil & Gas markets.

- The Brent's path was revised downwards in the short and medium term (until 2024) as a result of a contraction in the demand for oil never seen before and a reaction of supply that was insufficient to adjust to the low demand, despite the fact that the OPEC+ made the biggest production cut in its history and other producers have also taken heavy cuts.

- The Henry Hub path was revised upwards for 2021, due to the drop in gas production and the boost in the demand for gas for the electricity industry and electricity generation in the US, and the path was revised downwards in the medium and long term due to the expectation of greater penetration of renewable energies on a global scale and the consolidation of excess supply in the face of falling global demand.

The assumptions for the main price references are as follows:

	2021	2022	2023	2024	2025	2026-2032
Brent ($/ barrel)	49	55	58	62	67	59

Future cash flows are discounted to their present value at a specific rate for each CGU, determined based on the currency of its cash flows and the risks associated with them. The discount rate used by the Company is the weighted average cost of capital employed after tax for each country and business.

Cash flows are estimated on the basis of the outlook for their key variables in accordance with the expectations reflected in the annual budget and in the strategic plans for each business, in line with the new scenario of energy transition and decarbonization of the economy.

The discount rates used in 2020, 2019 and 2018 are as follows:

2020	2019	2018
7.36%	7.62%	8.16%

Valuations of the production assets of Exploration and Production (Upstream) use cash flow projections for a period that covers the economically productive useful lives of the oil and gas fields, limited by the contractual expiration of the operating permits, agreements or contracts. The general principles applied to determine the variables that most affect the cash flows of this business are described below:

- Oil and gas sales prices. The international benchmark price used by the Group are: Brent and HH (Henry Hub).

- Reserves, resources and production profiles. Production profiles are estimated on the basis of output levels at existing wells and the development plans in place for each productive field. As a consequence, these profiles are then used to estimate proved and unproved reserves and resources.

- Operating expenses and capital expenditure. These are calculated for the first year on the basis of the Group's annual budget and thereafter in keeping with the asset development programs, applying an escalation factor for operating expenses and investments basically of -1% to 1% (1% to 1.5% in 2019).

5.2.2 Estimation of crude oil and gas reserves and resources

The process of estimating oil and gas reserves is a key component of the Company's decision-making process. Oil and gas reserve estimates are used to calculate depreciation and amortization charges applying the unit-of-production ratio method and to assess the recoverability of the investments in the assets. Changes in reserve and resources could have a significant impact on the result.

The reserves are classified as follows:

a. Proved reserves: Proved reserves are those quantities of crude oil, natural gas and natural gas liquids that, with the information available to date, are estimated to be recoverable with reasonable certainty. There should be at least a 90% probability that the amounts recovered will equal or exceed the 1P estimate.

b. Probable reserves: Probable reserves are those additional reserves that, together with proved reserves, make up scenario 2P. There should be at least a 50% probability that the amounts recovered will equal or exceed the 2P estimate. This scenario reflects the best estimate of the reserves.

c. Developed reserves: Proved or probable quantities that are expected to be recovered from existing wells and facilities.

d. Undeveloped reserves: Proved or probable quantities that are expected to be recovered through future investments.

To estimate oil and gas reserves and resources, the Company uses the criteria established by the "SPE/WPC/AAPG/SPEE/SEG/ SPWLA/EAGE Petroleum Resources Management System", commonly referred to by its acronym SPE-PRMS (SPE standing for Society of Petroleum Engineers).

5.2.3 Provisions for litigation, dismantling and other contingencies

The Company makes judgements and estimates that affect the recognition and measurement of provisions for litigation, decommissioning and other contingencies. The final cost of settling complaints, claims and lawsuits may vary due to differences in the identification of dates, interpretation of rules, technical opinions and assessments of the amount of damages and liabilities.

The calculations to recognize provisions for the cost of decommissioning its oil and gas production operations are complex, on account of the need to initially recognize the present value of the estimated future costs and to adjust this figure in subsequent years in order to reflect the passage of time and changes in the estimates due to changes in the underlying assumptions used as a result of technological advances and regulatory changes, economic, political and environmental security factors, as well as changes in the initially-established schedules or other terms. The decommissioning provisions are updated regularly to reflect trends in estimated costs and the discount rates. These discount rates take into account the risk-free rate, by term and currency, country risk and the cash flow projection period. Specifically, the weighted average rate used by the Company was 2.36% (2019: 3.19% to 3.68%; 2018: 4.70% to 4.96%).

Additionally, the Company makes judgments and estimates in recording costs and establishing provisions for environmental clean-up and remediation costs, which are based on current information regarding costs and expected plans for remediation based on applicable laws and regulations, the identification and assessment of the effects on the environment, as well as sanitation technologies.

Therefore, any change in the factors or circumstances related to provisions of this nature, as well as changes in laws and regulations could, as a consequence, have a significant effect on the provisions recognized for these costs.

5.2.4 Calculation of income tax, tax credit and deferred tax assets

The appropriate assessment of the income tax expense is dependent on several factors, including estimates of the timing and realization of deferred tax assets and the timing of income tax payments. Collections and payments may be materially different from these estimates as a result of changes in the expected performance of the Company's businesses or in tax regulations or their interpretation, as well as unforeseen future transactions that impact the Company's tax balances.

During the financial year 2020 and 2019, a provision of $53,398 thousand is made for uncertain tax position of the Company in relation to the Petroleum (Income Tax) Act, 1967 ("PITA") on the deductibility of certain expenses and the Income Tax Act, 1967 ("CITA") on taxability of other income after utilising the prior years unutilised tax losses in Block PM3, and resulted in corresponding deferred tax assets of $26,300 thousand written off in year 2020.

The amount of tax provision is measured based on "most likely amount" method. The PITA provision is made in accordance to the Notice of Assessment ("NoA") received from Inland Revenue Board ("IRB") of Malaysia for Year Assessment ("YA")s 2015 and 2016 and estimation of the derived impacts in the subsequent YAs up to 2020. The CITA provision covers potential CITA tax and penalties on the YAs open for review by the IRB.

The tax matters on PITA are in the process of legal proceedings and the cases had been discussed in High Court. The High Court had granted the Company with an order of prohibition until the case is being decided in the Special Commissioners of Petroleum Income Tax ("SCPIT"). The Company is currently waiting for responses from SCPIT.

In relation to the tax matters on CITA, the Company had made an appeal via Form Q to the IRB against the Notices of Additional Assessment for YA2015 issued by IRB on January 29, 2021. The IRB had in its reply insisted that the additional assessment was correct and the Company is currently discussing with its legal counsel on the next action plan.

Due to the uncertainty associated with such tax items, there is a possibility that, on conclusion of open tax matters at a future date, the final outcome may differ significantly.

Deferred tax assets are only recognized when it is considered probable that the Company will have sufficient taxable income in the future against which they can be utilized.

Deferred tax assets are reviewed when there are indications of impairment, and in any event once a year, to verify that they still qualify for recognition and they are considered to be recoverable in the future, and the appropriate adjustments are made on the basis of the outcome of the analyses performed. These analyses are based on: (i) assumptions made to analyse the existence or otherwise of sufficient future earnings for tax purposes that might offset the tax losses or apply existing tax credits, based on the approach used to ascertain the presence of indications of impairment on its assets; (ii) the assessment of earnings estimates for the Company in accordance with the Company's business plans and the Group's overall strategic plan; and (iii) the statute of limitations period and other utilization limits imposed under prevailing legislation in the country for the recovery of the tax credits.

5.2.5 Calculation of expected credit loss

The Company has adopted the simplified expected credit loss model for its trade receivable, having its own risk assessment models for its customers and estimating the expected loss based on the probability of default, the balance at risk and estimated loss given default and taking into account the available information of each customer.

The remaining financial assets are individually monitored.

As a general criterion, 180 days past due is used to define credit-impaired financial instruments (in the absence of other evidence of default such as bankruptcy, etc).

The expected credit loss on financial instruments is calculated based on the stage of the debtor's credit risk statement.

- Phase 1: At the time of initial recognition, the expected credit loss is calculated with the probability of default in the first 12 months. In the case of trade receivables, the calculation is spread over the life of the instrument, in accordance with the accounting standard.
- Phase 2: When the instrument undergoes a significant increase in risk, the expected loss is calculated with the probability of default for the entire life of the instruments.
- Phase 3: When the instrument is already impaired, the expected loss for the entire life of the instrument is calculated and, in the event that interest accrues, it is calculated on the net balance of the provision of credit loss.

The assessment of the impairment of the value of the financial assets, to which the expected loss model is applicable, is calculated according to the following formula:

Expected credit loss = Probability of default x Exposure x Severity

Probability of default is calculated individually for each trade debtor according to the solvency models approved by the Repsol Group, except for individuals, from whom an average default rate is used. The models take into account quantitative information (economic-financial variables of the customer, external and internal payment behaviour, etc.), quantitative information (sector of activity, macroeconomic data on the country, etc.) and market sensitivity variables (e.g. price evolution). An internal rating and an associated probability of default are obtained for each debtor, according to the models.

Exposure is calculated taking into account the total amount of outstanding credit and a potential future exposure according to the available risk limit.

Severity reflects the percentage of unrecovered exposure in the event of default, taking into account whether or not such exposure is guaranteed, and is based on the behaviours of customers.

5.2.6 Extension and termination options of leases

In determining the lease term, management considers all facts and circumstances that create an economic incentive to exercise an extension option or not to exercise a termination option. Extension options or periods after termination options are only included in the lease term if the lease is reasonably certain to be extended or not terminated. The Company considers historical lease durations in determining whether to exercise the extension option.

As at 31 December 2020, potential future cash outflows of $1,428 thousand (undiscounted) have not been included in the lease liability because it is not reasonably certain that the leases will be extended ($3,804 thousand in 2019).

The lease term is reassessed if an option is actually exercised (or not exercised) or the Company becomes obliged to exercise (or not exercise) it. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment and this is within the control of the Company as a lessee. During the current financial year, the financial effect of revising lease terms to reflect the effect of exercising extension option was an increase in the recognised lease obligations and right-of-use assets of $1,368 thousand.

5.2.7 Allowance for inventories obsolescence

At the end of financial year, the Company reviews the carrying amount of the inventories to ensure that they are stated at the lower of cost and net realisable value. In assessing net realisable value and making appropriate allowances, management identifies inventories that are slow-moving and consider the inventories' physical conditions, market conditions and market price for similar items.

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6. Risk management

The Company is exposed to various risks that are particular to its core business of exploration, development and production. These risks arise in the normal course of the Company's business.

The Company's goal in risk management are to ensure that the management understands, measures and monitors the various risks that arise in connection with their operations. Policies and guidelines have been developed to identify, analyse, appraise and monitor the dynamic risks facing by the Company. Based on this assessment, each business unit adopts appropriate measures to mitigate these risks in accordance with the business unit's view of the balance between risk and reward.

The Company has exposure to foreign exchange risk, liquidity risk, credit risk, commodity price risk and interest rate risk arising from its use of financial instruments in the normal course of the Company's businesses.

6.1 Foreign exchange risk

The Company is exposed to currency risk as a result of the foreign currency transactions entered into by the Company in currencies other than its functional currency.

The net unhedged financial liabilities and assets of the Company that are not denominated in its functional currency at the reporting date are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Ringgit Malaysia ("MYR"):			
Cash and cash equivalents	36,796	27,904	42,391
Trade and other receivables	421	3,340	14,910
Trade and other payables	(31,463)	(73,585)	(63,162)
Due to related parties	-	(15)	-
Lease obligation	(3,386)	(4,265)	-
Total	**2,368**	**(46,621)**	**(5,861)**
Euro ("EUR"):			
Trade and other receivables	-	2	458
Due to related parties	12	(3,703)	(1,384)
Trade and other payables	(507)	(1,787)	(534)
Total	**(495)**	**(5,488)**	**(1,460)**
Pound Sterling ("GBP"):			
Trade and other receivables	-	2	279
Trade and other payables	(222)	(1,264)	(1,053)
Total	**(222)**	**(1,262)**	**(774)**
Singapore Dollar ("SGD"):			
Trade and other receivables	-	-	2
Trade and other payables	(9)	(43)	(41)
Total	**(9)**	**(43)**	**(39)**
Japanese Yen ("JPY"):			
Trade and other payables	(70)	-	-
	(70)	-	-

Sensitivity analysis for foreign currency risk

The Company is mainly exposed to the currencies of MYR, EUR and GBP, the exposure to SGD and JPY are deemed as not significant.

The following table details the Company's sensitivity to a two per cent increase and decrease in functional currency against the relevant foreign currencies. Two per cent is the sensitivity rate used when reporting foreign currency risk internally to key management personnel and represents management's assessment of the reasonably possible change in foreign exchange rates. A positive number below indicates an increase in profit net of tax where functional currency strengthens two per cent against the relevant foreign currency. For a two per cent weakening of functional currency against the relevant foreign currency, there would be a comparable impact on net profit after tax, and the balances below would be negative.

	USD'000 2020	USD'000 2019	USD'000 2018
USD/MYR:			
- strengthened 2% (2019: 2%, 2018: 2%)	(29)	578	73
- weakened 2% (2019: 2%, 2018: 2%)	29	(578)	(73)
USD/EUR:			
- strengthened 2% (2019: 2%, 2018: 2%)	6	68	18
- weakened 2% (2019: 2%, 2018: 2%)	(6)	(68)	(18)
USD/GBP:			
- strengthened 2% (2019: 2%, 2018: 2%)	3	16	10
- weakened 2% (2019: 2%, 2018: 2%)	(3)	(16)	(10)

6.2 Liquidity risk

The Company incurred a loss of $121,386 thousand for the financial year ended December 31, 2020. The Company's current liabilities exceeded its current assets by $4,224 thousand as at reporting date. These factors raise doubt that the Company will be able to continue as a going concern. Based on the projected cashflows prepared by management, the Company will have sufficient cash flows for the next twelve months from the date of the financial statements to meet their cash flow requirements. Therefore, the Company has prepared the financial statements on a going concern basis.

The Company actively manages its operating cash flows and the availability of funding to ensure that all refinancing, repayment and funding needs are met. As part of its overall prudent liquidity management, the Company maintains sufficient levels of cash to meet its working capital requirements.

The table below summarises the maturity profile of the Company's financial liabilities at the reporting date based on contractual undiscounted repayment obligations:

	USD'000 Less than one year	USD'000 From one to five years	USD'000 More than five years	USD'000 Total
2018				
Lease obligation	3,641	14,882	12,151	30,674
Due to related parties	2,673	-	-	2,673
Loan from related parties	10,968	-	-	10,968
Trade and other payables	134,569	18,086	-	152,655
Total	**151,851**	**32,968**	**12,151**	**196,970**
2019				
Lease obligation	7,046	23,420	13,576	44,042
Due to related parties	7,401	-	-	7,401
Trade and other payables	142,808	-	-	142,808
Total	**157,255**	**23,420**	**13,576**	**194,251**
2020				
Lease obligation	7,201	21,931	9,492	38,624
Due to related parties	1,111	-	-	1,111
Trade and other payables	54,434	-	-	54,434
Total	**62,746**	**21,931**	**9,492**	**94,169**

6.3 Credit risk

Credit risks, or the risk of counterparties defaulting, are controlled by the application of credit approvals, limits and monitoring procedures. The Company is exposed to credit risk, which is the risk that a customer or counterparty will fail to perform an obligation or settle a liability, resulting in credit loss to the Company. The Company's concentration of credit risk is mitigated by dealing with generally credit worthy large international oil and gas companies.

The Company minimises credit risk by entering into contracts with highly credit rated counterparties. Potential counterparties are subject to credit assessment and approval prior to any transaction being concluded and existing counterparties are subject to regular reviews, including re-appraisal and approval of granted limits. The creditworthiness of counterparties is assessed based on an analysis of all available quantitative and qualitative data regarding business risks and financial standing, together with the review of any relevant third party and market information. Reports are regularly prepared and presented to the management that cover the Company's overall credit exposure against limits and securities, exposure by segment and overall quality of portfolio.

The maximum exposure to credit risk for the Company is represented by the carrying amount of each financial asset.

A significant portion of these receivables are regular customers that have been transacting with the Company.

The Company uses ageing analysis and credit term review to monitor the credit quality of the receivables. Any customers exceeding their credit limit are monitored closely.

The Company determines the expected credit losses on trade receivable by using individual assessment, estimated based on historical credit loss experience of each individual receivable based on the past status of the adjusted as appropriate to reflect current conditions and estimates of future economic conditions. Accordingly, the credit risk profile of the trade receivables is presented based on their past due status.

For bank and financial institutions, only independently rated parties with minimum rating of above "A-" are accepted.

The loan to related party and amount due from related parties are considered low risk in default based on internal credit rating assessment since they are repayable on demand and do not have any past-due amounts.

The following shows the movement in expected credit loss that has been recognised for trade and other receivables

	USD'000 2020	USD'000 2019	USD'000 2018
Balance, beginning of year	4,750	7,204	13
Write-off	(1,007)	(3,281)	-
(Reversal)/Loss allowance on trade and other receivables	(111)	827	7,191
Balance, end of year	**3,632**	**4,750**	**7,204**

The Company's exposure to credit risk, according to the type of financial instrument together with the impairment recognized as at December 31 for each of them, is broken down as follows:

2020	**USD'000 Gross**	**USD'000 Impairment**	**USD'000 Net**
Accounts receivable, cash call receivables from partners net of prepayments and GST receivables			
- Not due	36,444	-	36,444
- 0 – 30 days past due	15,370	(3,590)	11,780
- 61 – 180 days past due	47	-	47
- More than 180 days past due	42	(42)	-
Loan to related party (not due)	12,703	-	12,703
Due from related parties (not due)	2,172	-	2,172
Cash and cash equivalents (not due)	48,090	-	48,090
Total	**114,868**	**(3,632)**	**111,236**

2019	USD'000 Gross	USD'000 Impairment	USD'000 Net
Accounts receivable, cash call receivables from partners net of prepayments and GST receivables			
- Not due	42,938	-	42,938
- 0 – 30 days past due	22,874	(4,685)	18,189
- More than 180 days past due	65	(65)	-
Loan to related party (not due)	18,995	-	18,995
Due from related parties (not due)	3,067	-	3,067
Cash and cash equivalents (not due)	68,885	-	68,885
Total	**156,824**	**(4,750)**	**152,074**
2018			
Accounts receivable, cash call receivables from partners net of prepayments and GST receivables			
- Not due	13,982	-	13,982
- 0 – 30 days past due	22,565	(7,140)	15,425
- 31 - 60 days past due	17	-	17
- More than 180 days past due	64	(64)	-
Due from related parties (not due)	1,508	-	1,508
Cash and cash equivalents (not due)	81,283	-	81,283
Total	**119,419**	**(7,204)**	**112,215**

The expected credit loss for amounts due from related parties, loan to related parties, cash and cash equivalents at December 31, 2020, 2019 and 2018 are immaterial.

6.4 Commodity price risk

As a result of the development of operations and commercial activities, the Company's results are exposed to the volatility of the prices of oil, natural gas and their derivatives.

The Company monitors its exposure to market risk in terms of sensitivities. These are supplemented by other risk measures on those occasions when the nature of the risk positions requires so.

6.5 Interest rate risk

The Company's primary interest rate risk relates to floating rate interest bearing borrowings from related companies. The Company manages its interest rate risk exposure on a transactional basis to achieve cheaper funding in a low interest rate environment and achieve a certain level of protection against rate hikes.

The movement in interest rates would not have any significant impact to the post-tax loss for the financial year.

6.6 Other risks

On March 11, 2020, the World Health Organization raised to the status of global pandemic the public health emergency caused by SARS-CoV-2 virus (commonly known as coronavirus, while COVID-19 denotes the disease caused by the virus). The rapid spread of COVID-19, on an international scale, has triggered an unprecedented healthcare, social and economic crisis that continues to evolve.

The economic impact of the pandemic, combined with pre-existing complications on the supply and demand side, has resulted in an exceptionally challenging pricing environment for oil and gas.

Even amid these difficult circumstances, the Company has sustained the safe operation of its business.

It is difficult to predict to what extent and for how long the impact of the pandemic will affect the Company's business in the future. The lower global demand for crude oil, gas and oil products as a result of the reduction in economic activity and, in particular, the restrictions to mobility, may have a negative impact on prices, production levels and sales volumes, the deterioration of global financial conditions may affect the cost of capital, liquidity or solvency on our customers and partners in joint operations, and so on.

7. Financial instruments

All the financial assets and financial liabilities of Company are measured at amortised costs. The following table analyses the financial assets and financial liabilities in the statement of financial position by the class of financial instruments to which they are assigned, and therefore by the measurement basis:

7.1 Classification of financial instruments

	USD'000 2020	USD'000 2019	USD'000 2018
Financial assets			
Amortised cost:			
Trade and other receivables net of prepayments and GST receivables	48,271	61,127	29,424
Loan to related party	12,703	18,995	-
Due from related parties	2,172	3,067	1,508
Cash and cash equivalents	48,090	68,885	81,283
Total	**111,236**	**152,074**	**112,215**
Financial liabilities			
Amortised cost:			
Lease obligation	32,405	37,420	24,181
Due to related parties	1,111	7,401	2,673
Loan from related parties	-	-	10,968
Trade and other payables	54,434	142,808	152,050
Total	**87,950**	**187,629**	**189,872**

8. Capital risk management

Capital management is defined as the process of managing the composition of the Company's debts.

The Company operates within clearly defined guidelines that are approved by Repsol, S.A., which is the ultimate holding company and it relies on the ultimate holding company for funding to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities as and when they fall due.

9. Intangible assets

	USD'000 Total
Cost	
Balance at January 1, 2018	1,100
Additions	100
Balance at December 31, 2018	**1,200**
Additions	1,348
Balance at December 31, 2019	**2,548**
Additions	1,174
Balance at December 31, 2020	**3,722**
Amortization	
Balance at January 1, 2018	-
Charge for the year	228
Balance at December 31, 2018	228
Charge for the year	635
Balance at December 31, 2019	**863**
Charge for the year	710
Balance at December 31, 2020	**1,573**
Net carrying value	
Balance at December 31, 2018	**972**
Balance at December 31, 2019	**1,685**
Balance at December 31, 2020	**2,149**

The intangible assets mainly consist of the implementation cost of the SAP Project One.

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10. Property, plant and equipment

	USD'000 Oil and gas properties	USD'000 Exploration and evaluation asset	USD'000 Capital Leases	USD'000 Total
Cost				
Balance at January 1, 2018	1,921,492	4,203	90,502	2,016,197
Additions	33,961	13,622	18,169	65,752
Change in ARO estimates	(44,196)	-	-	(44,196)
Transfer	1,667	(1,667)	-	-
Derecognition of capital leases*	-	-	(40,890)	(40,890)
Write-offs	(1,327)	(34)	(1,300)	(2,661)
Balance at December 31, 2018	**1,911,597**	**16,124**	**66,481**	**1,994,202**
Adjustment for change in accounting policies (Note 4.1)	-	-	(66,481)	(66,481)
Additions	49,878	2,385	-	52,263
Change in ARO estimates	(7,840)	-	-	(7,840)
Disposals	(142)	-	-	(142)
Write-offs	(229,543)	(13,831)	-	(243,374)
Balance at December 31, 2019	**1,723,950**	**4,678**	**-**	**1,728,628**
Additions	48,215	3,782	-	51,997
Change in ARO estimates	11,684	-	-	11,684
Transfer	2,214	(2,214)	-	-
Disposals	(18)	-	-	(18)
Write-offs	(759)	(2,803)	-	(3,562)
Balance at December 31, 2020	**1,785,286**	**3,443**	**-**	**1,788,729**
Accumulated depletion/ depreciation				
Balance at January 1, 2018	1,512,682	2,297	84,491	1,599,470
Charge for the year	63,418	-	3,275	66,693
Derecognition of capital leases*			(40,890)	(40,890)
Dry hole	-	13,611	-	13,611
Balance at December 31, 2018	**1,576,100**	**15,908**	**46,876**	**1,638,884**
Adjustment for change in accounting policies (Note 4.1)	-		(46,876)	(46,876)
Charge for the year	45,260	-	-	45,260
Dry hole	-	136	-	136
Disposals	(142)	-	-	(142)
Write-offs	(228,951)	(13,757)	-	(242,708)
Balance at December 31, 2019	**1,392,267**	**2,287**	**-**	**1,394,554**
Charge for the year	63,485	-	-	63,485
Disposals	(18)	-	-	(18)
Write-offs	-	(2,256)	-	(2,256)
Balance at December 31, 2020	**1,455,734**	31	**-**	**1,455,765**
Accumulated impairment				
Balance at January 1, 2018	5,177	-	-	5,177
Reversal of impairment	(1,735)	-	-	(1,735)
Balance at December 31, 2018	**3,442**	-	-	**3,442**
Reversal of impairment	(2,585)	-		(2,585)
Balance at December 31, 2019	**857**	-	-	**857**
Impairment	90,821	-	-	90,821
Balance at December 31, 2020	**91,678**	-	-	**91,678**
Net carrying value				
Balance at December 31, 2018	**332,055**	**216**	**19,605**	**351,876**
Balance at December 31, 2019	**330,826**	**2,391**	-	**333,217**
Balance at December 31, 2020	**237,874**	**3,412**	-	**241,286**

* Related to the expiry of PM305 Floating Storage and Offloading ("FSO").

Property, plant and equipment as at December 31, 2020 included $50,017 thousand ($37,687 thousand in 2019, $45,616 thousand in 2018) of costs that are not subject to depreciation, depletion and amortization as a result of development projects pending production, acquisition costs for probable reserves and exploration costs.

The extension of production period for Production Sharing Contract ("PSC") Block PM3 was granted up to December 31, 2027 for crude oil and natural gas. Block PM3 consists of 89 oil and gas active wells with 99 strings and 24 water and gas active injector wells with 26 strings. Block PM3 is located at the east of Peninsular Malaysia.

In 2020, the property, plant and equipment written off during the year mainly relate to previously impaired PM3 exploration due to no future development plans are expected. In 2019, the property, plant and equipment written off during the year mainly relate to the relinquishment of exploration block SB309 on December 16, 2019. In 2018, the property, plant and equipment written off during the year mainly relate to the de-recognition of capital lease assets and write-off of drilling inventories.

In 2020, in view of the situation in the commodity markets, the social and economic consequences of the COVID-19 pandemic, the Company carried out a review of the recoverable amount of the property, plant and equipment. The methodology used by the Company to estimate the recoverable amount of assets is, in general, the value in use is calculated by discounting to present value the future cash flows after tax expected to be derived from the operation of these assets. The review led to a recognition of impairment loss on property, plant and equipment of $90,473 thousand ($1,861 thousand of reversal in 2019, nil in 2018) which has been recognised in the statement of profit or loss and other comprehensive income. The key assumptions used in performing the impairment assessment are disclosed in Note 5.2.1 to the financial statements.

The reversal of impairment loss recognized in 2018 and 2019 was arising from the annual planed usage review for the drilling inventories performed by the Company which indicated that these inventories previously impaired can be utilised in the future period.

The Company has performed the following sensitivity analysis to assess impact from the changes in the key assumptions used to determine the recoverable amount to be recorded in oil and gas properties and right-of-use asset (Note 11) during the financial year 2020:

	Increase (+)/Decrease (-)	USD'000 Impairment losses	USD'000 Loss for the period
Change in oil and gas price	+10%	38,303	58,777
	-10%	192,120	212,594
Change in oil and gas production	+5%	60,926	81,400
	-5%	146,208	166,682
Change in discount rate	+1%	109,614	130,088
	-1%	90,372	110,540

The Company has taken out insurance policies to cover the risk of damage to its property, plant and equipment. The coverage of these policies is considered sufficient.

At December 31, 2020, 2019 and 2018, the Company has no commitments to purchase property, plant and equipment.

11. Right-of-use assets

This note provides information about ROU assets, expenses and cash flows related to leases.

Amount recognised in the statement of profit or loss and other comprehensive income as per below:

	USD'000 2020	USD'000 2019
Depreciation expense on ROU assets	6,159	9,902
Impairment losses on ROU assets (Note 22(f))	10,438	-
Interest expenses on leases (Note 17)	1,992	2,560
Expenses related to short-term leases (included in other operating expenses)	2,546	5,376

The total cash outflows for leases in 2020, including the payment made for short-term leases were $10,736 thousand ($17,118 thousand in 2019).

	USD'000 Buildings	USD'000 Vessels	USD'000 Computer software and equipment	USD'000 Total
Cost				
Balance at January 1, 2019	-	-	-	-
Adjustment for change in accounting policies (Note 4.1)	3,644	84,106	627	88,377
Additions	94	-	-	94
Balance at December 31, 2019	**3,738**	**84,106**	**627**	**88,471**
Additions	1,533	532	-	2,065
Change in estimates	-	(804)	(76)	(880)
Balance at December 31, 2020	**5,271**	**83,834**	**551**	**89,656**
Accumulated depreciation				
Balance at January 1, 2019	-	-	-	-
Adjustment for change in accounting policies (Note 4.1)	-	46,876	-	46,876
Charge for the year	1,794	7,801	307	9,902
Balance at December 31, 2019	**1,794**	**54,677**	**307**	**56,778**
Charge for the year	1,679	4,357	123	6,159
Balance at December 31, 2020	**3,473**	**59,034**	**430**	**62,937**
Accumulated impairment				
Balance at January 1, 2019/ December 31, 2019	-	-	-	-
Impairment	-	10,438	-	10,438
Balance at December 31, 2020	**-**	**10,438**	**-**	**10,438**
Net carrying value				
Balance at December 31, 2019	**1,944**	**29,429**	**320**	**31,693**
Balance at December 31, 2020	**1,798**	**14,362**	**121**	**16,281**

The impairment assessment carried out by the Company in 2020 as disclosed in Note 10 includes the review of the recoverable amount of the right-of-use assets. The review led to a recognition of impairment loss on right-of-use assets of $10,438 thousand which has been recognised in the statement of profit or loss and other comprehensive income. The sensitivity analysis to assess impact from the changes in the key assumptions used to determine the recoverable amount and the impairment loss to be recorded in right-of-use assets are disclosed in Note 10.

12. Joint Operations

In accordance with the terms by the joint operations, at the end of the 2020, 2019 and 2018 financial periods, the interest held by the Company in these investments are as follows:

	Working Interest	USD'000 2020 Revenue	USD'000 2019 Revenue	USD'000 2018 Revenue
PM3	22.30%	77,401	118,260	116,469
PM305/314	60%	4,346	19,658	27,086
Kinabalu	60%	110,282	114,794	172,596
SB309	70%	-	-	-
Total		**192,029**	**252,712**	**316,151**

The Company accounts for its investments in joint operations recording in its statement of financial position the proportionate share of the jointly controlled assets and jointly incurred liabilities that corresponds based on its percentage of participation (working interest).

Likewise, the corresponding part of the income generated and the expenses incurred by the joint operation are recognized in the statement of profit or loss and other comprehensive income.

On December 16, 2019, in light of completion of the minimum work commitment and minimum financial commitment by the Company, the Company had decided to relinquish Block SB309 PSC and JOA.

13. Sinking fund

	USD'000 2020	USD'000 2019	USD'000 2018
Balance, beginning of year	60,749	52,384	41,113
Abandonment cess payment during the year	6,955	17,001	15,720
Revisions in discount	2,538	(4,491)	(4,515)
Accretion expense	1,614	(2,016)	1,182
Reversal/(Impairment losses)	483	(2,793)	-
Foreign exchange	189	664	(1,116)
Balance, end of year	**72,528**	**60,749**	**52,384**

The Company contributed to a separate fund established to fund future decommissioning obligations. The balance at December 31, 2020 amounts $72,528 thousand ($60,749 thousand in 2019, $52,384 thousand in 2018). As of December 31, 2020, the review of the recoverable amount of the sinking fund had led to an impairment reversal of $483 thousand as a result of change in ARO estimates for PM305/314. As of December 31, 2019, the impairment losses of $2,793 thousand was recognised due to overpayment of abandonment cess fund for PM305/314.

14. Trade and other receivables

	USD'000 2020	USD'000 2019	USD'000 2018
Accounts receivable	9,709	8,785	11,020
Accounts receivables from partners (underlift)	2,390	12,239	2,113
Cash call receivables from partners	39,079	55,979	22,590
GST receivables	43	3,466	11,285
Less: Loss allowance during the year	(3,632)	(4,750)	(7,204)
Total trade and other receivables	**47,589**	**75,719**	**39,804**
Prepayments	2,691	3,082	3,025
Deposits	725	826	904
Total	**51,005**	**79,627**	**43,733**

The Company is exposed to credit risk, which is the risk that customer or counterparty will fail to perform an obligation or settle a liability, resulting in financial loss to the Company. The maximum credit risk exposure associated with trade and other receivables is the carrying value. At December 31, 2020 the Company had trade receivable of $9,709 thousand ($8,807 thousand in 2019, $11,041 thousand in 2018), 39% of which is receivable from PETRONAS, the Malaysian national oil company, 59% of which is receivable from PetroVietnam, the Vietnamese national oil company and 2% of which is receivable from other customers.

Crude oil production is sold to PETCO Trading Labuan Company, a wholly owned subsidiary of PETRONAS. Natural gas production is sold at the wellhead to PETRONAS. Accounts receivable have arisen primarily from these sales and are expected to be received in full.

Accounts receivables from partners refers to the oil product that the Company was entitled to, based on the production sharing contract, of which lifted by partners. At each reporting date, the amount is valued at the lower of current market value and fair value at the date of lifting. As at December 31, 2020, these receivables of $2,096 thousand will be settled via cash (2019: $287 thousand, 2018: $2,113 thousand).

Cash call receivables from partners refer to funding receivable from partners relates to Production Sharing Contract expenditures and working capital.

15. Inventories

	USD'000 2020	USD'000 2019	USD'000 2018
Materials and supplies inventory	16,468	16,982	18,196
Total	**16,468**	**16,982**	**18,196**

Materials and supplies inventory mainly comprises of spare parts, equipment, steel line pipe, pressure vessels and other equipment that required maintaining in order to support the day-to-day production operation.

Inventories recognised as an expense during the year ended December 31, 2020 amounted to $4,232 thousand ($8,379 thousand in 2019, $10,650 thousand in 2018) and included in supplies in the statement of profit or loss and other comprehensive income.

The production inventories written off during the year amounted to $924 thousand ($2 thousand in 2019, $736 thousand in 2018) and these were recognised as an expense during the year ended December 31,2020.

As at December 31, 2020, the provisions made for the production inventories amounted to $744 thousand ($994 thousand in 2019 offset with reversal of $1,027 thousand, $1,027 thousand in 2018) as a result of annual material review. These were included in other operating expense in the statement of profit or loss and other comprehensive income.

16. Loan to/from related party

16.1 Loan to related party

	USD'000 RIF
Balance at January 1, 2019	-
Draws during the year	38,800
Repayments during the year	(20,000)
Interest during the year	195
Balance at December 31, 2019	**18,995**
Draws during the year	15,700
Repayments during the year	(22,028)
Interest during the year	36
Balance at December 31, 2020	**12,703**

On June 17, 2019, the Company and Repsol International Finance B.V ("RIF") has entered into a credit contract for a principal amount of $50,000 thousand. The contract matured on June 17, 2020. Full or partial repayment of the principal is allowed at any time during the credit contract period as agreed between the Company and RIF. The loan is unsecured and the interest charges are based on LIBOR 3M minus 5 basis point.

On June 17, 2020, an amendment to the credit contract dated June 17, 2019 was made between the Company RIF. As a result, the loan maturity has been extended to June 17, 2021. The interest for each interest period is LIBOR 3M, minus 6 basis point.

16.2 Loan from related party

	USD'000 TEHS1	USD'000 TEHS2	USD'000 RGDSL	USD'000 Total
Balance at January 1, 2018	72,724	15,656	-	88,380
Draws during the year	1,234	2,796	42,000	46,030
Repayments during the year	-	-	(126,035)	(126,035)
Interest during the year	1,026	98	1,469	2,593
Transfer of loan	(74,984)	(18,550)	93,534	-
Balance at December 31, 2018	-	-	**10,968**	**10,968**
Draws during the year	-	-	24,844	24,844
Repayments during the year	-	-	(35,958)	(35,958)
Interest during the year	-	-	146	146
Balance at December 31, 2019	-	-	-	-
Draws during the year	-	-	48,000	48,000
Repayments during the year	-	-	(48,193)	(48,193)
Interest during the year	-	-	193	193
Balance at December 31, 2020	-	-	-	-

On April 7, 2017, TE Holdings S.A.R.L ("TEHS 1") loaned $114,512 thousand to the Company. Interest is based on each interest period at LIBOR 3M, plus 2.5%. Accrued interest is due on repayment of borrowings and any outstanding interest payable at month end if not paid in cash is added to the principal. The loan matures on April 7, 2018. The loan was transferred to Repsol Tesoreria Y Gestion Financiera,S.A. ("RTYGF") and subsequently to Repsol Gestion Divisa, S.L. ("RGDSL") during the year.

On November 15, 2017, TE Holdings S.A.R.L ("TEHS 2") loaned $15,611 thousand to the Company as part of the Malaysia trade balance clearing. Interest is based on a LIBOR 1Y flat rate. The interest is set daily. Accrued interest is due on repayment of borrowings and any outstanding interest payable at month end if not paid in cash is added to the principal. The loan matures on September 30, 2018. The loan was transferred RTYGF and subsequently to RGDSL during the year.

On April 26, 2018, Repsol Gestion Divisa, S.L. ("RGDSL") loaned $42,000 thousand to the Company. Interest is based on each Interest period at LIBOR 12M, plus 1.66% (LIBOR 12M, plus 1.3% in 2019). Accrued interest is due on repayment of borrowings. The loan matures on April 26, 2019 and was repaid in full on May 9, 2019.

On April 26, 2019 and 2020 respectively, an amendment to the credit contract dated April 26, 2018 was made between RGDSL and the Company. As a result, the agreement has been further extended to April 26, 2020 and April 26, 2021. The loan was then repaid in full during 2019 and 2020.

RIF, TEHS1, TEHS2 and RGDSL are share a common ultimate holding company (Repsol, S.A.).

17. Trade and other payables

	USD'000 2020	USD'000 2019	USD'000 2018
Long-term payable	2,041	1,611	19,148
Long-term lease obligation	25,204	30,374	20,540
Total non-current	**27,245**	**31,985**	**39,688**
Trade payables and others	19,804	37,698	25,910
Accrued liabilities	34,630	86,924	108,599
Current signature bonus payable	-	18,186	-
Current lease obligation	7,201	7,046	3,641
Unearned revenue	-	-	60
Total current	**61,635**	**149,854**	**138,210**

17.1 Long-term payable

Long-term payable as of December 31, 2018 of $17,541 thousand corresponds to the outstanding balance due to host governments related to the PSC Block PM3 Extension signature bonus. Total PM3 signature bonus amounted to $60,000 thousand with the balance payable by the Company in February 2020. Therefore, the balance is recognised as current payable as of December 31, 2019.

Long-term payable as of December 31, 2020 of $2,041 thousand ($1,611 thousand in 2019, $1,607 thousand in 2018) represents the utilisation of Petronas Carigalis Sdn Bhd ("PCSB") tax losses for Block PM-305 and PM-314 for the years ended December 31, 2013 and December 31, 2020. This amount will be returned to PCSB in future years when PCSB is in a tax payable position. The movement of $430 thousand in 2020 is due to the estimated utilisation of PCSB's tax losses based on the current tax provision of the year ended December 31, 2020.

17.2 Lease obligation

Lease obligation as of December 31, 2018 relates to the lease for the Northern Fields which commenced on March 25, 2009. The 10-year Primary Term shall expire on March 25, 2019. The lease was subsequently extended for an additional 10 years, with effect from January 1, 2018.

On adoption of MFRS 16/IFRS 16 effective from January 1, 2019, the lease is recognised as part of the lease obligation as of December 31, 2019 in the statement of financial position. The changes in accounting policies are reflected in Note 3.20.

The Company leases various offices, vessels and computer software and equipment. Rental contracts are typically made for fixed period of 2 to 20 years.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The lease agreements do not impose any covenants, but leased assets may not be used as security for borrowing purpose.

At December 31, 2020, $38,624 thousand ($44,042 thousand in 2019, $30,674 thousand in 2018) has been identified as the total undiscounted liability of the Company. This is discounted at the rate ranging from 3.71% to 9.38% (2019: 4.56% to 9.65%, 2018: 5.69%). Total lease payments incurred in 2020 was $8,190 thousand ($11,742 thousand in 2019, $3,380 thousand in 2018). Interest expense on the long-term lease obligation incurred in 2020 was $1,992 thousand ($2,560 thousand in 2019, $1,437 thousand in 2018).

	USD'000 2020	USD'000 2019	USD'000 2018
Minimum lease payments			
Less than one year	7,201	7,046	3,641
One to five years	21,931	23,420	14,882
More than five years	9,492	13,576	12,151
Total future minimum lease payments	**38,624**	**44,042**	**30,674**
Less: future finance charges	(6,219)	(6,622)	(6,493)
Present value of lease obligation	**32,405**	**37,420**	**24,181**

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	USD'000 2020	USD'000 2019	USD'000 2018
Present value of lease obligation			
Less than one year	7,201	7,046	3,641
One to five years	16,670	18,203	9,480
More than five years	8,534	12,171	11,060
Total	**32,405**	**37,420**	**24,181**

There are no contingent rentals paid during the year (nil in 2019 and 2018).

17.3 Other current liabilities

Trade payables and others are unsecured and are usually paid within 30 days of recognition.

Current element of lease relates to amount payable for leasing of PM3 Northern Field Ocean Going Vessel ("PM-3") contract.

On adoption of MFRS 16/IFRS 16 effective from January 1, 2019, the current obligations relate to the leasing of various offices, vessels and computer software and equipment as described in Note 17.2.

Carrying amount of current liabilities does not significantly defer from its fair value.

18. Provisions and contingencies

18.1 Asset retirement obligation ("ARO")

ARO movement during 2020, 2019 and 2018 is as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Asset retirement obligation, beginning of year	128,465	135,648	179,200
Accretion	4,176	6,429	7,323
Liabilities incurred and revisions in estimate	11,461	(13,612)	(50,875)
Asset retirement obligation, end of year	**144,102**	**128,465**	**135,648**

The estimated undiscounted asset retirement obligation at December 31, 2020 was $168,502 thousand ($162,810 thousand in 2019, $200,135 thousand in 2018) and is expected to be incurred near the end of the respective terms of the Company's PSC:

- PM-3 CAA: 2023 (2%), 2024 (1%), 2025 (7%), 2026 (1%), 2027 (11%), 2028 (78%)
- PM-305: 2021 (32%), 2022 (16%), 2023 (52%)
- PM-314: 2021 (83%), 2022 (17%)
- Kinabalu: 2022 (4%), 2026 (4%), 2029 (20%), 2032 (13%), 2033 (59%).

The ARO has been discounted using a discount rate at 2.36% (2019: 3.19% to 3.68%, 2018: 4.70% to 4.96%).

Total accretion for the year ended December 31, 2020 of $4,176 thousand ($6,429 thousand in 2019, $7,323 thousand in 2018) has been included in finance expenses (see Note 22(g)).

18.2 Provisions

Provisions movement during 2020, 2019 and 2018 is as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Provisions, beginning of year	716	566	210
Liabilities incurred during the year	202	150	356
Amount used or reversed during the year	(378)	-	-
Provisions, end of year	**540**	**716**	**566**

At December 31, 2020, the provision of $511 thousand ($666 thousand in 2019, $566 thousand in 2018) relates to the bonus incentives to be granted to the employees of the Company and these are determined at the discretion of the management. Of this provision, $242 thousand are expected to be paid in 2021 and the remaining is to be paid over the years from 2022 to 2024. The bonus incentives related to the year of 2019 amounting to $241 thousand was paid out during the year, and therefore the remaining unused amount of $87 thousand was reversed out.

The remaining provision of $29 thousand relates to the provision for free share for every 2 shares subscribed by employee in relation to Repsol Global Share Purchase Plan (SPP). Under SPP, eligible employee who enrolled to the plan will received one share for every two shares purchased. The plan last for 3 years starting from FY2020 and the free shares will be granted in Jan 2023.

In 2019, a chemical spill happened onshore and a site assessment had been carried out in early 2020. Therefore, the provision made for the site assessment of $50 thousand was no longer required in current financial year.

19. Commitments

Major commitments for the Company as at December 31, 2020 include costs associated with the PM-3 CAA extension, PM-3 Southern Field and PM-3 Northern Field Support Vessels.

19.1 Non-cancellable operating lease commitments

On adoption of MFRS 16/IFRS 16 effective on January 1, 2019, leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company. Therefore, no operating lease commitment disclosure is required for 2019 and 2020.

	USD'000 2018
Future minimum rental payable:	
Within one year	4,786
Later than one year and not more than five years	16,269
Later than five years	5,674
Total	**26,729**

19.2 Capital commitments in respect of investment in petroleum operations in Malaysia

Capital expenditures not provided for in the financial statements are estimated to be as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Authorised and contracted for	40,030	36,894	36,602

20. Share Capital

The Company's authorized share capital consists of an unlimited number of common shares without nominal or par value. The number of shares issued and outstanding were 12,000 as at December 31, 2020 (12,000 in 2019 and 2018), in the amount of $12 thousand ($12 thousand in 2019 and 2018).

At December 31, 2020, 2019 and 2018, Fortuna International Petroleum Corporation owns 100% of the Company's share capital.

The shares of the Company are not listed on any Stock Exchange.

21. Income taxes

	USD'000 2020	USD'000 2019	USD'000 2018
Tax income attributable to profit is made up of:			
CURRENT CORPORATE INCOME TAX			
Current year	(5,892)	(485)	(204)
Previous years corporate tax provision	(22,687)	(8,208)	-
(Under)/Over provision in prior year	(289)	495	(86)
Total	**(28,868)**	**(8,198)**	**(290)**
DEFERRED CORPORATE INCOME TAX			
Recognition of temporary difference	(5,909)	(36,577)	12,873
Total	**(5,909)**	**(36,577)**	**12,873**
Total income tax (expense)/recovery	**(34,777)**	**(44,775)**	**12,583**

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The Company accounts for income taxes using the taxes liability method. As a result, the Company's income tax expense varies from the amount that would otherwise result from the application of the statutory income tax rates as set out below:

	USD'000 2020	USD'000 2019	USD'000 2018
(Loss)/Profit before income taxes	(86,609)	68,250	70,887
Expected income tax expense at Barbados corporate tax rate (2020 - 2.5%; 2018, 2019 – 1.5%)	2,165	(1,024)	(1,063)
Non-deductible expenses	(2,863)	(6,114)	(20,688)
Income not subject to tax	32	162	794
Foreign tax rate differential	13,332	(36,019)	(7,645)
(Under)/Over provision in prior year	(289)	495	(86)
Previous years tax provision	(48,987)	(8,208)	-
Change in Barbados tax rate (1.5% to 2.5%)	1,833	-	-
Utilisation of unused tax losses and deductible temporary differences not recognised as deferred tax assets ("DTA")	-	5,933	41,271
Income tax (expense)/recovery	**(34,777)**	**(44,775)**	**12,583**

Previous years corporation tax provision expense in amount of $22,687 thousand ($8,208 thousand in 2019) correspond to the additional tax and penalty for Block PM3 for the year of assessment 2014 to 2016, as well as to corporate income tax for the year of assessment 2015 to 2017 and potential tax and penalties on the YAs open for review by the Inland Revenue Board of Malaysia ("IRB"). Prior years unutilized tax losses in PM3 have been offset in the value of previous years corporate tax provision mentioned above, and hence the corresponding DTA on the tax losses of $26,300 thousand is written off in 2020.

As at December 31, 2018, the amount of unrecognised temporary difference was $15,020 thousand and this had been recognised as deferred tax asset as at December 31, 2019.

Deferred Tax expense is attributable to the recognition of temporary differences under Barbados tax legislation and Malaysia Income tax regulation (Petroleum Income Tax regulation ("PITA"), under which Malaysian Petroleum Sharing Contracts are taxed), and correspond mainly to the difference between tax and accounting depreciation and amortization, abandonment provision and sinking fund, as well as to the utilization of tax losses generated in previous years.

The movement of the deferred tax assets/(liabilities) of the Company are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Balance at January 1	36,336	72,918	60,041
Credit/(Charge) to profit or loss			
Property, plant and equipment	13,371	4,752	99,563
Right of use assets	5,664	(12,519)	-
Sinking fund	(6,999)	(5,104)	19,922
Underlift of crude oil	3,228	(3,405)	2,040
Leases	(1,533)	4,494	(93)
Asset retirement obligation	7,087	(4,853)	(73,728)
Overlift of crude oil	(9)	(1,785)	(5,281)
Unutilised tax losses	(26,888)	(19,034)	(28,332)
Adjustment on adoption of MFRS 9/IFRS 9	-	-	5
Others	170	877	(1,219)
Exchange differences	(12)	(5)	-
Balance at December 31	**30,415**	**36,336**	**72,918**

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax relate to the same tax authority. The following amounts, determined after appropriate offsetting, are shown in the statement of financial position:

	USD'000 2020	USD'000 2019	USD'000 2018
Deferred tax assets	101,938	123,123	144,301
Deferred tax liabilities	(71,523)	(86,787)	(71,383)
Balance at December 31	**30,415**	**36,336**	**72,918**

The amounts of the deferred tax assets are mainly composed by the temporary differences generated by the asset retirement obligation, lease obligation and tax losses, while the amounts of deferred tax liabilities are composed by temporary differences between tax and accounting depreciation and amortization and by the temporary differences generated by the sinking fund.

The components and movements of deferred tax liabilities and assets during the financial year prior to offsetting are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
DEFERRED TAX ASSETS			
Lease obligation	12,150	13,683	9,189
Asset retirement obligation	45,553	38,466	43,319
Overlift of crude oil	153	162	1,947
Unutilised tax losses	43,924	70,812	89,846
Others	158	-	-
Total	**101,938**	**123,123**	**144,301**
DEFERRED TAX LIABILITIES			
Property, plant and equipment	(42,784)	(56,155)	(60,907)
Right-of-use assets	(6,855)	(12,519)	-
Sinking fund	(21,362)	(14,363)	(9,259)
Underlift of crude oil	(522)	(3,750)	(345)
Others	-	-	(872)
Total	**(71,523)**	**(86,787)**	**(71,383)**

The domestic income tax is calculated according to PITA statutory rate of 38% (2019 and 2018: 38%) of the estimated assessable profit from Petroleum Operations in Malaysia. In particular, the Block PM-3 is a disputed maritime overlapping claim between Malaysia and the Socialist Republic of Vietnam. On that basis, the Petroleum Income Tax collection for this area is also shared between the Government of Malaysia and Government of Vietnam and that the PSC Contractors have been paying the Petroleum Income Tax to the tax authorities of both countries although the tax submission is only made to the Malaysian Inland Revenue Board ("MIRB").

The Company was previously licensed under the International Business Companies Act Cap. 77 which has been repealed. The Company continues its licensing under the Companies Act Cap. 308. which allows provision for the same previous benefits via grandfathering under the International Business Companies (Repealed) Act, 2018-40, until the Company transitions to the new regime in 2021. The Company qualified for grandfathering. As a result the tax rates remain at 1.0% to 2.5%.

On the repeal of the International Business Companies Act, Cap. 77., the Income Tax Act Cap. 73 was amended to apply new staggered tax rates from 1.0% to 5.5% based on the Company's income. The revised tax rates effective January 1, 2020 are as follows: taxable income up to $500 Thousand is subject to tax at 5.5%, taxable income exceeding $500 Thousand up to the next $10,000 Thousand at 3.0%, taxable income exceeding $10,000 Thousand up to $15,000 Thousand at 2.5% and all amounts in excess of $15,000 Thousand at 1.0%.

Long Term tax receivable in amount of $6,387 thousand ($6,387 thousand in 2019, $9,182 thousand in 2018) corresponds to the amount of petroleum income taxes overpaid to Vietnamese tax Authority in prior years, and expected to be received within more than one year.

Income tax payable in amount of $35,298 thousand ($11,862 thousand in 2019) correspond to the additional tax and penalty for Block PM3 for the year of assessment 2014 to 2016. The remaining income tax payable is related to corporate income tax for the year of assessment 2015 to 2017 amounting to $18,100 thousand and income tax payable to Malaysia Inland Revenue Board, Vietnamese Tax Authority and Barbados Revenue Authority amounting to $5,499 thousand.

22. Revenue and expenses

(a) Operating revenue

Revenue from sales is broken-down as follows:

	USD'000 Crude oil	USD'000 Gas	USD'000 Total
2018			
Thailand	104,438	-	104,438
China	7,546	-	7,546
India	49,473	-	49,473
Malaysia	14,748	13,364	28,112
Vietnam	-	62,432	62,432
Japan	9,881	-	9,881
Australia	54,269	-	54,269
Total sales	**240,355**	**75,796**	**316,151**
2019			
Thailand	97,903	-	97,903
China	3,131	-	3,131
India	47,827	-	47,827
Malaysia	26,067	17,331	43,398
Vietnam	-	36,500	36,500
Australia	23,953	-	23,953
Total sales	**198,881**	**53,831**	**252,712**
2020			
Thailand	40,026	-	40,026
China	27,345	-	27,345
India	83,014	-	83,014
Malaysia	4,345	17,384	21,729
Vietnam	-	17,094	17,094
Australia	2,821	-	2,821
Total sales	**157,551**	**34,478**	**192,029**

The Company derives its revenue from contracts with customers from the above geographical markets for the sales of crude oil and gas.

(b) Personnel expenses

Personnel expenses are broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Salaries, wages and allowances	32,715	44,159	54,136
Defined contribution benefits	4,032	4,297	5,538
Social security costs	84	259	138
Total	**36,831**	**48,715**	**59,812**
Capitalised as part of oil and gas properties	1,753	2,387	2,674

The number of employees at December 31, 2020 is 359 (392 in 2019, 483 in 2018).

The distribution of the Company's personnel by position levels at the reporting date are broken-down as follows:

	USD'000 Total
2018	
Non-executive	53
Executive	420
Management	10
Total	**483**
2019	
Non-executive	65
Executive	317
Management	10
Total	**392**
2020	
Non-executive	57
Executive	292
Management	10
Total	**359**

(c) Depletion, depreciation and amortization

Depletion, depreciation and amortization are broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Depletion, depreciation and amortization of oil and gas properties (Note 10)	63,485	45,260	63,418
Dry hole expenses (Note 10)	-	136	13,611
Depreciation of capital lease (Note 10)	-	-	3,275
Amortization of intangible assets (Note 9)	710	635	228
Total	**64,195**	**46,031**	**80,532**
Depreciation and amortization of right-of-use assets (Note 11)	6,159	9,902	-
Total	**70,354**	**55,933**	**80,532**

(d) Other operating expenses

Other operating expenses are broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Rental	2,546	5,376	4,324
Inventories written off	924	2	736
Write-down of inventories	744	-	1,027
Oil and gas properties written off (Note 10)	1,306	666	1,362
Repair and maintenance	20,944	23,122	42,486
De-recognition of capital lease assets (Note 10)	-	-	1,300
Professional services	8,142	6,766	2,113
Other taxes	18,373	37,918	37,401
Freight charges	3,384	9,532	12,471
Insurance	2,264	3,614	4,981
Administrative expense	431	15,367	11,528
Tax penalties (Note 21)	18,739	3,654	-
COVID-19 related expense	1,110	-	-
Other expenses	6,623	3,380	13,882
Total	**85,530**	**109,397**	**133,611**

(e) Other operating income

	USD'000 2020	USD'000 2019	USD'000 2018
Other miscellaneous income	1,599	1,852	91
Partners' recovery for personnel expense	28,223	34,671	43,819
Other exceptional income	223	5,772	6,679
Reversal of write-down of inventories	-	33	-
Total	**30,045**	**42,328**	**50,589**

Other exceptional income is related to recognition of the revision in the estimate of ARO into the statement of profit or loss and other comprehensive income because the decrease in ARO has exceeded the carrying amount of the related assets recorded in oil and gas properties.

(f) Net impairment losses

	USD'000 2020	USD'000 2019	USD'000 2018
Impairment losses/(reversal) on property, plant and equipment	90,821	(2,585)	(1,735)
Impairment losses on right-of-use assets	10,438	-	-
(Reversal)/impairment losses on sinking fund	(483)	2,793	-
Total	**100,776**	**208**	**(1,735)**

The impairment losses and its reversal relate to the amount recognised during the year as a result of the annual impairment assessment. Detailed information is disclosed in Notes 5.2.1, 10, 11 and 13.

(g) Financial income/(expenses)

Financial result is broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Interest income on miscellaneous	52	588	433
Interest income on loan to related party (Note 16)	36	195	-
Total finance income	**88**	**783**	**433**
Interest expense on lease (Note 17)	(1,992)	(2,560)	(1,437)
Interest expense on others	(92)	(722)	(1,227)
Interest expense on loan from related party (Note 16)	(193)	(146)	(2,593)
	(2,277)	**(3,428)**	**(5,257)**
Accretion expense for ARO (Note 18)	(4,176)	(6,429)	(7,323)
Accretion expense for sinking fund (Note 13)	4,152	(6,507)	(3,333)
	(24)	**(12,936)**	**(10,656)**
Total finance expenses	**(2,301)**	**(16,364)**	**(15,913)**

Accretion expense for ARO is the unwinding of the interest of discounted long-term ARO liabilities.

Accretion expense for sinking fund consists of revision in discount rate (2020: 0.74% to 3.06%, 2019: 3.00% to 3.60%, 2018: 3.20% to 3.52%) and the accretion expense of the sinking fund.

	USD'000 2020	USD'000 2019	USD'000 2018
Net unrealised loss on foreign exchange	(366)	2,489	(1,261)
Net realised gain on foreign exchange	368	217	589
Total foreign exchange gain/(loss)	**2**	**2,706**	**(672)**

23. Related parties

23.1 Related parties' balances and transactions

Balances with related parties as at December 31, 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Amount due to:			
Ultimate holding company			
Repsol, S.A.	225	3,714	1,385
Intermediate holding company			
Repsol Exploracion, S.A.	824	2,709	233
Related companies			
Repsol Oil & Gas Canada Inc.	-	13	97
Repsol Oil & Gas USA, LLC	-	-	4
Repsol Oil & Gas SEA Pte. Ltd.	-	553	429
Repsol Services Company	15	57	262
Repsol Oil & Gas RTS Sdn. Bhd.	39	347	234
Repsol Oil & Gas Malaysia (PM3) Limited	-	-	29
TE Holdings S.A.R.L	-	8	-
Repsol Trading S.A.	1	-	-
Repsol Tesoreria y Gestion Financiera	7	-	-
Due to related parties	**1,111**	**7,401**	**2,673**
Loan from related company:			
Repsol Gestion Divisa, S.L	-	-	10,968
Loan from a related party	**-**	**-**	**10,968**
Amount due from related companies:			
Talisman Sakakemang B.V.	-	-	1
Talisman Vietnam 07/03 B.V.	-	-	2
Repsol Oil & Gas Canada Inc.	1	-	-
Talisman Vietnam Limited	2,152	3,067	1,504
Repsol Tesoreria y Gestion Financiera	-	-	1
Repsol Ecuador,S.A. (Suc)	19	-	-
Due from related parties	**2,172**	**3,067**	**1,508**
Loan to related company:			
Repsol International Finance B.V.	12,703	18,995	-
Loan to a related party	**12,703**	**18,995**	**-**
Cash call receivables from related company:			
Repsol Oil & Gas Malaysia (PM3) Limited	5,054	11,247	-
Cash call receivables from related company	**5,054**	**11,247**	**-**

The amounts due to/from related parties which mainly arose from non-trade transactions are unsecured, non-interest bearing and are repayable on demand.

Loan to/from related party are detailed in Note 16.

The material related party transactions for 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Loan to related party			
- Repsol International Finance B.V.			
At January 1	18,995	-	-
Loans advanced	15,700	38,800	-
Loans repayment received	(21,800)	(20,000)	-
Interest charged	36	195	-
Interest received	(228)	-	-
At December 31	**12,703**	**18,995**	**-**

Repsol Oil & Gas Malaysia Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

	USD'000 2020	USD'000 2019	USD'000 2018
Loans from related parties:			
- TE Holdings S.A.R.L.	-	-	
At January 1			88,380
Loans advanced	-	-	4,030
Loans repayment made	-	-	-
Interest charged	-	-	1,124
Interest paid	-	-	-
Loans transferred to Repsol Gestion Divisa, S.L.	-	-	(93,534)
At December 31	-	-	-
- Repsol Gestion Divisa, S.L.			
At January 1	-	10,968	-
Loans advanced	48,000	24,844	42,000
Loans repayment made	(48,000)	(33,219)	(126,035)
Interest charged	193	146	1,469
Interest paid	(193)	(2,739)	-
Loans transferred from TE Holdings S.A.R.L.	-	-	93,534
At December 31	-	-	10,968
Technical and administrative expense to:			
- Repsol, S.A.	4,490	9,194	7,362
- Repsol Exploracion, S.A.	3,090	10,774	-
Total technical and administrative expense	7,580	19,968	7,362
Processing fee charged to:			
- Talisman Vietnam Limited	976	1,337	1,157

In the normal course of business, the Company undertakes a variety of transactions with certain companies, each of whom share a common ultimate holding company (Repsol, S.A.) and intermediate holding company (Repsol Exploracion, S.A.).

The holding companies incurred certain reimbursable expenditure on behalf of the Company.

In 2020, Repsol, S.A and Repsol Exploración, S.A charged the Company $4,490 thousand and $3,090 thousand respectively ($9,194 thousand and $10,774 thousand in 2019; $7,362 thousand in 2018) for technical and administrative services provided to the Company.

23.2 Information referring to the Directors

Remuneration and other benefits paid to the Directors

In 2020, the Company has paid $10.8 thousand to its Directors for attending to the functions inherent to the Company management ($12.6 thousand in 2019, $12.2 thousand in 2018).

At December 31, 2020, 2019 and 2018, the Company had not assumed any obligations regarding pensions or life insurance for its Directors, nor were any advances, loans or credits made to them by the Company.

24. Production sharing contract

The Company secures the rights to carry out exploration activities in the international blocks through a Production Sharing Contract ("PSC") arrangement with respective national oil company.

Under the terms of the PSC that the Company has entered into, the PSC contractor bears all costs. The PSC contractor funds the work outlined in the approved Work Programme and Budget ("WP&B") and upon production, may recover the costs in barrels of crude oil or gas equivalent (referred to as "cost oil" or "cost gas"), in accordance with the terms of the PSC. Costs remaining unrecovered can be carried forward for recovery against production of crude oil or gas equivalent in subsequent quarter. The contractor's share of production also includes an element of profit (referred to as "profit oil" or "profit gas").

Title to all equipment and other assets purchased or acquired by the PSC contractor exclusively for the purpose of petroleum operations, and which costs are recoverable in barrels of cost oil or gas equivalent are vested with the national oil company. The contractors retain the right of use of those assets for the duration of the PSCs and the corresponding value of the right of these assets is minimised in the financial statements of the Company as intangible assets and plant and equipment.

The Company recognises the cost of dismantling and removing the assets and restoring the site on which they are located when there is an obligation to do so.

25. Events subsequent to year end

Since the end of 2020, there have been no significant events that could affect the financial statements for 2020 or normal course of the Company's business.

Effective June 30, 2021 the benefits under the International Business Companies Act (Repealed) Act 2018-40 will expire. The company will be required to comply with the Companies (Economic Substance) Act, 2019-43 (CESA) with effect from January 1, 2021. The Act imposes an economic substance test on Barbados-resident companies that are managed and controlled in Barbados or incorporated/registered in Barbados and not considered a tax resident in another jurisdiction. The Act also requires that the companies conduct relevant activities as defined under the Act. The Company is in compliance with the new Act based on the management's assessment.

26. Other information

26.1 Claims

A claim for unlawful dismissal had been initiated by a former employee of the Company on May 21, 2018 and it is currently under trial. The potential payment that the Company could be required to make to its former employee should there be any adverse outcome related to this lawsuit is estimated to be approximately $208 thousand. The court hearing had been completed on April 6, 2021 and is currently waiting for the court judgment. The Company considers it is probable that the judgement will be in its favour and has therefore not recognised a provision in relation to this claim as of year-end.

26.2 Performance guarantees

As of December 31, 2020, the Company has provided a bank guarantee amounting to $129 thousand ($126 thousand in 2019, $125 thousand in 2018) as a security for lease of Kemaman Supply Base facilities under the tenancy agreement entered with Pangkalan Bekalan Kemaman Sdn.Bhd.. The guarantee is renewed annually and is effective from August 8, 2020 and expires on August 7, 2021.

The Company has also provided bank guarantees amounting to $89 thousand ($102 thousand in 2019, $96 thousand in 2018) in total to Director-General Custom of Malaysia for the utilisation of the platforms as docking points, loading and movement of goods in connection with upstream operations pursuant to the Customs Act 1967. These guarantees will expire in 2021 with the expiry dates throughout the period from March 14, 2021 to October 6, 2021 (2019: March 14, 2020 to October 19, 2020, 2018: March 14, 2019 to October 6, 2019).

As of December 31, 2019, the Company has provided a bank guarantee amounting to $49 thousand ($48 thousand in 2018) to Director-General Custom of Malaysia as a security for the movement of land transportation pursuant to custom form 8 and this is effective from June 6, 2019 to June 5, 2020.

As of December 31, 2018, the Company has provided a bank guarantee amounting to $38 thousand to Director-General Custom of Malaysia for crude sales management on behalf Petrovietnam and PVEP for Block PM3-CAA.

27. Reconciliation of liabilities arising from financing activities

The table below details the reconciliation of the opening and closing amounts for the liabilities for which cash flows have been, or would be classified as financing activities in the statement of cash flows:

Loans from related parties

	USD'000 2020	USD'000 2019	USD'000 2018
At January 1	-	10,968	88,380
Cash flows from:			
- Principal:			
Drawdown	48,000	24,844	46,030
Repayment	(48,000)	(33,219)	(126,035)
- Interest paid	(193)	(2,739)	-
Interest charged	193	146	2,593
At December 31	**-**	**-**	**10,968**

Lease obligations

	USD'000 2020	USD'000 2019	USD'000 2018
At January 1	37,420	24,181	7,956
Implementation of MFRS 16/IFRS 16 (Note 4.1)	-	22,330	-
Cash flows from lease payment	(8,190)	(11,742)	(3,380)
New lease	2,065	94	18,168
Change in estimates	(880)	-	-
Foreign exchange	(2)	(3)	-
Interest charged	1,992	2,560	1,437
At December 31	**32,405**	**37,420**	**24,181**

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The Board of Directors
Hibiscus Petroleum Berhad
2nd floor,
Syed Kechik Foundation Building,
Jalan Kapas, Bangsar,
59100 Kuala Lumpur.

4 October 2021

PwC/TEH/NNH/sw/0896B1

Dear Sirs,

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia (PM3) Limited

Our Opinion

We have audited the accompanying financial statements of Repsol Oil & Gas Malaysia (PM3) Limited ("RMP" or the "Target Company") which comprise the statements of financial position as at 31 December 2018, 31 December 2019 and 31 December 2020, the statements of profit or loss and other comprehensive income, statements of changes in shareholder's equity and statements of cash flows for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, and a summary of significant accounting policies and other explanatory notes (together, the "Financial Statements"), as set out on pages 1 to 42. The Financial Statements have been prepared for purposes of inclusion in Hibiscus Petroleum Berhad ("HPB")'s circular to shareholders of HPB (the "Circular to Shareholders") in connection with the proposed acquisition of Fortuna International Petroleum Corporation and its subsidiaries by HPB (the "Proposal").

In our opinion, the Financial Statements give a true and fair view of the financial position of the Target Company as at 31 December 2018, 31 December 2019 and 31 December 2020 and of its financial performance and cash flows for each of the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS").

PricewaterhouseCoopers PLT (LLP0014401-LCA & AF 1146), Chartered Accountants, Level 10, 1 Sentral, Jalan Rakyat, Kuala Lumpur Sentral, P.O. Box 10192, 50706 Kuala Lumpur, Malaysia
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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0896B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia (PM3) Limited (Continued)

Basis for Opinion

We conducted our audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing. Our responsibilities under those standards are further described in the Reporting Accountant's Responsibilities for the Audit of the Financial Statements section of our report. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence and Other Ethical Responsibilities
We are independent of the Target Company in accordance with the By-Laws (on Professional Ethics, Conduct and Practice) of the Malaysian Institute of Accountants ("By-Laws") and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) ("IESBA Code"), and we have fulfilled our other ethical responsibilities in accordance with the By-Laws and the IESBA Code.

Directors' Responsibilities for the Financial Statements

The Directors of the Target Company are responsible for the preparation of the Financial Statements for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020 that gives a true and fair view in accordance with the MFRS and IFRS. The Directors of the Target Company are also responsible for such internal control as the Directors of the Target Company determine is necessary to enable the preparation of the Financial Statements that is free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements of the Target Company, the Directors of the Target Company are responsible for assessing the Target Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors of the Target Company either intend to liquidate the Target Company or to cease operations, or have no realistic alternative but to do so.

Reporting Accountant's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements of the Target Company as a whole are free from material misstatement, whether due to fraud or error, and to issue a report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with approved standards on auditing in Malaysia and International Standards on Auditing will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0896B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia (PM3) Limited (Continued)

Reporting Accountant's Responsibilities for the Audit of the Financial Statements (Continued)

As part of an audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Financial Statements of the Target Company, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Target Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors of the Target Company.
- Conclude on the appropriateness of the Directors of the Target Company's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Target Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our report to the related disclosures in the Financial Statements of the Target Company or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our report. However, future events or conditions may cause the Target Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the Financial Statements of the Target Company, including the disclosures, and whether the Financial Statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Directors of the Target Company regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0896B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Repsol Oil & Gas Malaysia (PM3) Limited (Continued)

Restriction on Distribution and Use

This report is issued for the sole purpose of inclusion in the Circular to Shareholders of HPB in connection with the Proposal, and should not be relied on for any other purposes. Accordingly, we will not accept any liability or responsibility to any other party to whom our report is shown or into whose hands it may come.

Yours faithfully,

PricewaterhouseCoopers PLT

PRICEWATERHOUSECOOPERS PLT
LLP0014401-LCA & AF 1146
Chartered Accountant

REPSOL OIL & GAS MALAYSIA (PM3) LIMITED

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

Repsol Oil & Gas Malaysia (PM3) Limited

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

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Repsol Oil & Gas Malaysia (PM3) Limited
Financial statements for the financial years ended 31.12.2020, 31.12.2019 and 31.12.2018

Repsol Oil & Gas Malaysia (PM3) Limited

STATEMENTS OF FINANCIAL POSITIONS

(U.S. dollars)	Note	USD'000 As at 31.12.2020	USD'000 As at 31.12.2019	USD'000 As at 31.12.2018
Assets				
Intangible assets	9	322	411	153
Property, plant and equipment	10	56,873	110,637	117,911
Right-of-use assets	11	8,007	16,387	-
Sinking fund	13	21,966	15,917	12,742
Long term tax receivable	21	5,044	3,353	3,286
Non-current Assets		**92,212**	**146,705**	**134,092**
Inventories	15	7,356	7,415	7,204
Trade and other receivables	14	4,942	8,307	6,673
Due from related party	23	-	-	27
Income tax receivable	21	1,980	-	-
Cash and cash equivalents		939	5,790	4,660
Current Assets		**15,217**	**21,512**	**18,564**
Total Assets		**107,429**	**168,217**	**152,656**
Shareholder's equity and Liabilities				
Share capital	20	11,668	11,668	11,668
Retained earnings		(28,482)	24,679	20,503
Shareholder's equity		**(16,814)**	**36,347**	**32,171**
Asset retirement obligation	18	44,904	41,910	39,021
Long-term payable	17	-	-	9,948
Long-term lease obligation	17	14,276	16,962	11,654
Deferred tax liabilities	21	351	24,063	14,593
Non-current Liabilities		**59,531**	**82,935**	**75,216**
Due to related parties	23	5	12	-
Loans from related parties	16,23	18,216	16,637	41,385
Trade and other payables	17	7,863	24,498	2,984
Income tax payable	21	38,628	7,788	900
Current Liabilities		**64,712**	**48,935**	**45,269**
Total Shareholder's equity and Liabilities		**107,429**	**168,217**	**152,656**

Notes 1 to 27 are an integral part of the financial statements.

Approved by Khoo Pool Yin on behalf of the Directors on October 4, 2021:

Repsol Oil & Gas Malaysia (PM3) Limited

STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
FOR THE YEARS ENDED

(U.S. dollars)	Note	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Sales	12, 22a	43,938	65,592	68,450
Revenue		**43,938**	**65,592**	**68,450**
Change in underlift		(4,556)	4,620	-
Supplies		(1,673)	(3,456)	2,973
Other operating expenses	22c	(28,326)	(26,883)	(25,946)
Depletion, depreciation and amortization of non-current assets	22b	(17,968)	(13,117)	(23,521)
Depreciation and amortization of right-of-use assets	22b	(2,480)	(2,821)	-
Net impairment losses	22e	(47,382)	4,253	1,214
Other operating income	22d	326	527	4,697
Results from operating activities		**(58,121)**	**28,715**	**27,867**
Finance income	22f	81	72	84
Finance expenses	22f	(1,140)	(9,586)	(5,848)
Foreign exchange gain/(loss)	22f	89	254	(266)
Net finance expense		**(970)**	**(9,260)**	**(6,030)**
(Loss)/Profit before income taxes		**(59,091)**	**19,455**	**21,837**
Income tax expense	21	5,930	(15,083)	(10,960)
(Loss)/Profit for the period		**(53,161)**	**4,372**	**10,877**
Total comprehensive (loss)/income for the period		**(53,161)**	**4,372**	**10,877**

Notes 1 to 27 are an integral part of the financial statements.

Repsol Oil & Gas Malaysia (PM3) Limited

STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
FOR THE YEARS ENDED

		USD'000	
	Share capital	Retained earnings	Total
At 01.01.2018	**11,668**	**9,630**	**21,298**
MFRS 9/IFRS 9 adjustment	-	(4)	(4)
Total comprehensive income for the period	-	10,877	10,877
At 31.12.2018/01.01.2019	**11,668**	**20,503**	**32,171**
MFRS 16/IFRS 16 adjustment (Note 4.1)	-	(196)	(196)
Total comprehensive income for the period	-	4,372	4,372
At 31.12.2019/01.01.2020	**11,668**	**24,679**	**36,347**
Total comprehensive loss for the period	-	(53,161)	(53,161)
At 31.12.2020	**11,668**	**(28,482)**	**(16,814)**

Notes 1 to 27 are an integral part of the financial statements.

Repsol Oil & Gas Malaysia (PM3) Limited

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED

(U.S. dollars)	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Cash flows from Operating Activities			
(Loss)/Profit for the period before tax	(59,091)	19,455	21,837
Adjustments to income:			
Depletion, depreciation and amortization	20,448	15,938	23,521
Net impairment losses	47,382	(4,253)	(1,214)
Interest expense	1,855	2,702	3,190
Accretion expense	(715)	6,884	2,658
Foreign exchange (gain)/loss	(89)	(254)	266
Inventory written off	394	1	79
Write-down/(Reversal) of inventory	318	(85)	484
Interest income	(81)	(72)	(84)
Oil and gas properties written off	222	201	458
(Write-back)/Loss allowance on trade and other receivables	(9)	(46)	51
Change in asset retirement obligation estimates	-	-	(4,270)
De-recognition of capital lease assets	-	-	714
Changes in working capital:			
Inventories	*(653)*	*(127)*	*599*
Trade and other receivables	*3,373*	*(1,588)*	*5,757*
Trade and other payables	*(7,315)*	*12,557*	*(22,589)*
Changes in related parties	*(7)*	*39*	*3*
Interest received	81	72	84
Cash flows from Operating Activities	**6,113**	**51,424**	**31,544**
Cash flows from Investing Activities			
Sinking fund	(3,946)	(8,225)	(4,735)
Capital expenditures	(4,104)	(12,115)	(10,641)
Cash flows used in Investing Activities	**(8,050)**	**(20,340)**	**(15,376)**
Cash flows from Financing Activities			
Loans from related parties	25,500	12,334	5,500
Repayment of loans from related parties	(24,726)	(38,200)	(15,556)
Interest paid	(17)	(379)	(692)
Long-term lease	(3,671)	(3,709)	(1,918)
Cash flows used in Financing Activities	**(2,914)**	**(29,954)**	**(12,666)**
Net (decrease)/increase in cash and cash equivalents	**(4,851)**	**1,130**	**3,502**
Cash and cash equivalents, beginning of year	5,790	4,660	1,158
Cash and cash equivalents, end of year	939	5,790	4,660

Note:
The cash and cash equivalents comprise cash and short-term deposits which are denominated in RM and USD. The short-term deposit has a maturity period of 5 days (2019: 7 days). The interest rates for the deposits range from 1.60% (2019: 2.80%)

Notes 1 to 27 are an integral part of the financial statements.

Repsol Oil & Gas Malaysia (PM3) Limited
Notes to the financial statements for the years ended 31.12.2020, 31.12.2019, 31.12.2018

1. General information

This Accountants' Report contains the financial statements of Repsol Oil & Gas Malaysia (PM3) Limited (hereinafter, "the Company") which comprise the statements of financial position as at December 31, 2020, December 31, 2019 and December 31, 2018, the statements of profit or loss and other comprehensive income, statements of changes in Shareholder's equity and statements of cash flows for the financial years ended December 31, 2020, December 31, 2019 and December 31, 2018, and a summary of significant accounting policies and other explanatory notes. The financial statements were prepared by management and approved by the Directors of the Company.

The Company was incorporated on December 10, 2001 under the Barbados Companies Act Cap 308 (the "Act"). On April 18, 2016 the Articles of the Company were amended to change the name of the Company from Talisman Malaysia (PM3) Limited to Repsol Oil & Gas Malaysia (PM3) Limited. The Company was licensed and operates under the International Business Companies Act.

Effective January 1, 2019, the International Business Companies Act Cap. 77 was repealed, and all companies licensed under this act prior to its repeal, are now licensed under the Companies Act Cap. 308. Existing licensees have until 2021 to transition into the regime and have the benefit of grandfathering provisions until they do so under the International Business Companies (Repealed) Act 2018-40. In conjunction with the repeal of the International Business Companies Act Cap. 77, the Income Tax Act Cap. 73 was also amended. The amended Income Tax Act Cap. 73 applies new effective and staggered rates of tax from 1.0% to 5.5% based on a Company's net income. The Company elected to be grandfathered in accordance with International Business Companies (Repeal) Act, 2018-40 of Barbados until June 30, 2021. As a result the tax rates remain at 1.0% to 2.5%.

The Company's immediate parent was Repsol Oil & Gas Malaysia Holdings Limited ("RMHL"). RMHL amalgamated with Fortuna International Petroleum Corporation on August 31, 2017. As a result of the amalgamation, the immediate parent is Fortuna International Petroleum Corporation.

The Company's ultimate parent company was Talisman Energy Inc ("TEI"). On May 8, 2015, Repsol, S.A. acquired all of the outstanding common shares of TEI and on January 1, 2016, the legal name of TEI was changed to Repsol Oil & Gas Canada Inc. ("ROGCI"). As a result of the acquisition, the ultimate parent undertaking is Repsol, S.A. while the intermediate parent is Repsol Exploración, S.A.. Repsol, S.A.

The Company is in the business of exploration, development, production and marketing of crude oil, natural gas and natural gas liquids in Malaysia and Vietnam. The Company commenced commercial operations on April 1, 2002.

The Company jointly with Repsol Oil & Malaysia Limited ("RML"), PETRONAS Carigali Sdn Bhd ("CARIGALI") and Petrovietnam Exploration Production Corporation Limited ("PVEP") are contractor parties under a Production Sharing Contract ("PSC") dated February 16, 1989 with Petroliam Nasional Berhad ("PETRONAS") and Vietnam Oil & Gas Group ("Petrovietnam") for the purpose of exploration, exploitation, winning and obtaining of petroleum resources offshore Block PM-3 CAA. In addition to the PSC, the Company and the Contractor parties are parties to a Joint Operating Agreement ("JOA") for the joint operations of the Block PM-3 CAA. The Company has a participating interest of 15% in the PSC for Block PM-3 CAA. The initial term of the PSC was until February 15, 2017 for crude oil production and December 13, 2018 for natural gas production.

Pursuant to an Addendum to the PSC dated April 16, 2016, the parties had agreed to extend the Block PM-3 CAA PSC and JOA until December 13, 2027. In addition, the participating interest of the Company was also amended under the Addendum to 12.67% ("New Participating Interest") effective February 16, 2017 for the crude oil production and December 14, 2018 for the natural gas production. With regards to the Bunga Kekwa Sub Block in the Block PM-3 CAA, the New Participating Interest for the crude oil production of the aforesaid Sub Block would be applicable from October 29, 2013.

A unitisation agreement was signed between PETRONAS and Petrovietnam on February 10, 2000 whereby it was agreed that East Bunga Kekwa - Cai Nuoc Field will be developed and exploited by the PM3 CAA Group and Block 46 Group, effective from June 10, 1998. The tract participation interest of the PM3 CAA Group is 75.9508%.

The registered office of the Company is 1st Floor, Limegrove Centre, Holetown, St. James, Barbados.

The address of the place of business of the Company is Level 33, Menara Citibank, 165, Jalan Ampang, 50450 Kuala Lumpur.

The Company is part of a group of companies under the terms of article 42 of the Code of Commerce, Repsol Group, whose ultimate parent company is Repsol, S.A. Repsol, S.A. is registered at the Madrid Companies Register in sheet no. M-65289. Its registered office is in Madrid, 44 Méndez Álvaro Street.

The items included in the financial statements of the Company are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The functional currency of the Company is United States Dollar ("USD").

2. Basis of preparation of the financial statements

The financial statements of the Company for the year ended December 31, 2020, December 31, 2019 and December 31, 2018 have been prepared in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS") which include the Statement of financial position, Statement of Profit or Loss and Other Comprehensive income, Statement of Changes in Shareholder's equity, Statement of Cash Flows and Notes.

The preparation of financial statements in conformity with MFRS/IFRS requires the use of certain critical accounting estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reported period. It also requires the Directors to exercise their judgment in the process of applying the Company's accounting policies. Although these estimates and judgment are based on the directors' best knowledge of current events and actions, actual results may differ. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 5 to the financial statements.

The financial statements reflect only the Company's interest in entitlement under the Production Sharing Contract ("PSC") and share of cost and assets and liabilities under the Joint Operating Agreements.

2.1 Amendments to published standards that are effective

Effective for annual period beginning on/after January 1, 2018

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2018:

- MFRS 9/IFRS 9 'Financial Instruments'
- MFRS 15/IFRS 15 'Revenue from Contracts with Customers'
- IFRIC 22 'Foreign Currency Transactions and Advance Consideration'

The Company has adopted MFRS 9/IFRS 9 and MFRS 15/IFRS 15 for the first time in the 2018 financial year, which resulted in changes in accounting policies. The Company accounting policies on financial instruments and revenue stream are disclosed in details in Notes 3.8, 3.9 and 3.15 respectively. The impact from the adoption of these standards has been disclosed throughout the financial statements and is not material to the Company.

Effective for annual period beginning on/after January 1, 2019

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2019:

- MFRS 16/IFRS 16 'Leases'
- Amendments to MFRS 9/IFRS 9 'Prepayment Features with Negative Compensation'
- Amendments to MFRS 128/IAS 28 'Long-term Interests in Associates and Joint Ventures'
- Amendments to MFRS 119/IAS 19 'Plan Amendment, Curtailment or Settlement'
- IFRIC 23 'Uncertainty over Income Tax Treatments'
- Annual Improvements to MFRSs/IFRSs 2015 - 2017 Cycle

The Company has adopted MFRS 16/IFRS 16 and IFRIC 23 for the first time in the 2019 financial year, which resulted in changes in accounting policies. The information on new accounting policies are disclosed in details in Note 4.

Other than MFRS 16/IFRS 16 and IFRIC 23, the adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

Effective for annual period beginning on/after January 1, 2020

The Company has applied the following amendments to the standards for the first time for the financial year beginning on January 1, 2020:

- The Conceptual Framework for Financial Reporting (Revised 2018)
- Amendments to MFRS 101/IAS 1 and MFRS 108/IAS 8 'Definition of Material'
- Amendments to MFRS 9/IFRS 9, MFRS 139/IAS 39 and MFRS 7/IFRS 7 'Interest Rate Benchmark Reform'

The adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

2.2 Amendments to published standards that have been issued but not yet effective

Effective for annual period beginning on/after June 1, 2020

- In May 2020, the IASB issued COVID-19-Related Rent Concessions (Amendment to MFRS 16/IFRS 16) that grant an optional exemption for lessees to account for rent concessions occurring as a direct consequence of COVID-19.

  Such concessions might take a variety of forms, including payment holidays and deferral of lease payments. In many cases, this will result in accounting for the concession as a variable lease payment in the period(s) in which the event or condition that triggers the reduced payment occurs.

  The optional exemption permits a lessee to elect not to assess whether a COVID-19-related rent concession is a lease modification. A lessee that makes this election shall account for any change in lease payments resulting from the COVID-19-related rent concession the same way it would account for the change applying MFRS 16/IFRS 16 if the change were not a lease modification.

  The practical expedient applies only to rent concessions occurring as a direct consequence of COVID-19 and only if all of the following conditions are met:
  - The change in lease payments results in revised consideration for the lease that is substantially the same as, or less than, the consideration for the lease immediately preceding the change;
  - Any reduction in lease payments affects only payments originally due on or before June 30, 2021 (a rent concession meets this condition if it results in reduced lease payments on or before June 30, 2021 and increased lease payments that extend beyond June 30, 2021); and
  - There is no substantive change to other terms and conditions of the lease.

  The amendments shall be applied retrospectively.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

Effective for annual period beginning on/after January 1, 2022

- The amendments to MFRS 116/IAS 16 'Property, Plant and Equipment ("PPE")- Proceeds before Intended Use' prohibit an entity deducting from the cost of an item of property, plant and equipment the proceeds received from selling items produced by the property, plant and equipment before that asset is ready for its intended use, i.e. proceeds while bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Consequently, an entity recognises such sales proceeds and related costs in profit or loss.

  The amendments also clarify the meaning of 'testing whether an asset is functioning properly'. IAS 16/MFRS 116 now specifies this as assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes.

  If not presented separately in the statement of comprehensive income, the financial statements shall disclose the amounts of proceeds and cost included in profit or loss that relate to items produced that are not an output of the entity's ordinary activities, and which line item(s) in the statement of comprehensive income include(s) such proceeds and cost.

  The amendments are applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments.

The entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the beginning of that earliest period presented.

- The amendments to MFRS 137/IAS 37 'Onerous Contracts – Cost of Fulfilling a Contract' specify that the 'cost of fulfilling' a contract comprises the 'costs that relate directly to the contract'. Costs that relate directly to a contract consist of both the incremental costs of fulfilling that contract, as well as an allocation of other costs that relate directly to fulfilling contracts. The amendments also clarify that before recognising a separate provision for an onerous contract, impairment loss that has occurred on assets used in fulfilling the contract should be recognised.

  The amendments shall be applied retrospectively and apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments. Comparatives are not restated.

  Instead, the entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings or other component of equity, as appropriate, at the date of initial application.

- Annual Improvements to MFRS/IFRS Standards 2018–2020 (Effective date 1 January 2022)

  The following improvements were finalised in May 2020:

  - MFRS 9/IFRS 9 Financial Instruments – clarifies which fees should be included in the 10% test for derecognition of financial liabilities.

  - MFRS 16/IFRS 116 Leases – amendment of illustrative example 13 to remove the illustration of payments from the lessor relating to leasehold improvements, to remove any confusion about the treatment of lease incentives.

  - MFRS 1/IFRS 1 First-time Adoption of International Financial Reporting Standards – allows entities that have measured their assets and liabilities at carrying amounts recorded in their parent's books to also measure any cumulative translation differences using the amounts reported by the parent. This amendment will also apply to associates and joint ventures that have taken the same MFRS 1/IFRS 1 exemption.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

<u>Effective for annual period beginning on/after January 1, 2023</u>

- Amendments to MFRS 101/IAS 1 - Disclosure of accounting policy information - require entities to disclose their material rather than their significant accounting policies (Effective date 1 January 2023).

- Amendments to MFRS 108/IAS 8 - Definition of accounting estimates - clarifies how companies should distinguish changes in accounting policies from changes in accounting estimates (Effective date 1 January 2023).

- Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to MFRS 112/ IAS12) - require companies to recognise deferred tax on transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences (Effective date 1 January 2023).

- The amendments to MFRS 101/IAS 1 'Classification of Liabilities as Current or Non-current' affect only the presentation of liabilities as current or non-current in the statement of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items.(Effective date 1 January 2023)

  The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants are complied with at the end of the reporting period, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

3. Significant accounting policies

3.1 Basis of accounting

The financial statements of the Company have been prepared under the historical cost convention unless otherwise stated in the accounting policies mentioned below. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

3.2 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Company takes into account the characteristics of the asset or liability if market participants would take those characteristic into account when pricing the asset or a liability at the measurement date. Fair value for measurement and/or disclosure purposes in these financial statements is determined on such a basis, except for any share-based payment transactions that are within the scope of MFRS 2/IFRS 2, leasing transactions that are within the scope of MFRS 16/MFRS 117/IFRS 16/IAS 17, and measurements that have some similarities to fair value but are no fair value, such as net realisable value in MFRS 102/IAS 2 or value-in-use in MFRS 136/IAS 36.

In addition, for financial reporting purposes, fair value measurements are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value measurements are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

3.3 Classification of assets and liabilities into current and non-current

In the accompanying statement of financial position, assets and liabilities maturing within twelve months are classified as current items and those maturing in more than twelve months are classified as non-current items.

3.4 Intangible Assets

Intangible assets comprise implementation cost of the SAP Project One and expenditure on the exploration for and evaluation of oil and gas resources directly associated with an exploration well, including license acquisition and drilling costs, are initially capitalised as intangible assets until the results have been evaluated. During the exploration and evaluation phase, these costs are not amortized, although they are tested for impairment at least once a year and whenever indications of impairment are detected. Once the exploration and evaluation phase is completed, if no reserves are found, the amounts previously capitalized are recognized as an expense in the statement of profit or loss and other comprehensive income. If the exploration work does yield positive results, giving rise to commercially exploitable wells, costs are reclassified to "*Oil and gas properties*" at their carrying amount when this determination is made.

Exploration costs other than G&G costs ("Exploration rights and geology and geophysical costs"), excluding the costs of drilling exploration wells and exploration licenses, are recognized as an expense in the statement of profit or loss and other comprehensive income when incurred.

3.5 Property, Plant and Equipment

The Company uses the cost model by which items of property, plant and equipment are measured initially at acquisition cost.

The cost of property, plant and equipment includes their acquisition cost, all the costs directly related to the location of assets and all the costs to make them operational.

Additionally, if applicable, the cost of property, plant and equipment includes the present value of the expected disbursements necessary for any costs of dismantling and removing the item or restoring the site on which it is located, when such obligations are incurred under certain conditions. Subsequent changes to the measurement of the dismantling obligations and related liabilities resulting from changes in the estimated cash flows and/or in the discount rate are added to or deducted from the asset's carrying amount in the period in which they are incurred, except where the lower corrected value of the liability is greater than the carrying amount of the associated asset, in which case the surplus is recognized in the statement of profit or loss and other comprehensive income.

Borrowing costs that are directly attributable to the acquisition or construction of assets that require more than one year to be ready for use are capitalized as part of the cost of these assets, in accordance with the limits established in the applicable accounting rules.

Personnel expenses and other operating expenses directly attributable to the construction of the asset are also capitalized.

The costs of expansion, modernization or improvements leading to increased productivity, capacity or efficiency or to a lengthening of the useful lives of the assets are capitalized, as long as the general capitalization criteria are met.

Repair, upkeep and maintenance expenses are recognized in the statement of profit or loss and other comprehensive income as incurred. Furthermore, certain facilities require periodic reviews. In this respect, the assets subject to replacement are recognized specifically and are depreciated over the average term remaining until the next repairs are carried out.

Property, plant and equipment, other than those items relating to oil and gas exploration and production activities, are depreciated using the straight-line method on the basis of the acquisition cost of the assets less their estimated residual value, over the years of estimated useful life of the assets.

Depreciation of these assets starts when the assets become available for use.

Recognition of oil and gas exploration and production assets

The Company recognizes hydrocarbon exploration and production operations using accounting polices mostly based on the "successful efforts" method. Under this method, the various costs incurred are treated as follows for accounting purposes:

i. The costs incurred in the acquisition of new interests in areas with proved and unproved reserves are capitalized as incurred under "*Oil and gas properties*" item of property, plant and equipment.

ii. The costs of acquiring exploration permit and the geological and geophysical (G&G) costs incurred during the exploration phase are capitalized under "*Oil and gas properties*". They are not amortized during the exploration and evaluation phase and they are tested for impairment at least once a year and, in any case, when there is an indication that they may have become impaired, in accordance with the indicators of MFRS 6/IFRS 6 Exploration for and evaluation of mineral resources. Once the exploration and evaluation phase is over, if no economically viable reserves are found, the amounts capitalized are recognized as an expense in the statement of profit or loss and other comprehensive income.

iii. *Exploratory drilling costs*, including those relating to stratigraphic exploration wells, are recognized as assets until it is determined whether proved reserves justifying their commercial development have been found. If no reserves are found, the capitalized drilling costs are registered in the statement of profit or loss and other comprehensive income. In the event that reserves are found but remain under evaluation for their classification as proved, their recognition depends on the following:

   - If additional investments are required prior to the start of production, they continue to be capitalized whilst the following conditions are met: (i) the amount of proved reserves found justifies the completion of a productive well if the required investment is carried out, and; (ii) satisfactory progress has been made in the evaluation of reserves and the operational viability of the project. If any of these conditions fail to be met, they are treated as impaired, and are expensed in the statement of profit or loss and other comprehensive income.

   - In all other cases, if there is no commitment to carry out significant activities to evaluate reserves or develop the project within a reasonable period after well drilling has been completed, or if activities have been halted, they must be recorded as an expense in the statement of profit or loss and other comprehensive income.

   - Costs incurred in exploratory drilling work that has yielded a commercially exploitable reserve are reclassified to "*Oil and gas properties*" under property, plant and equipment at their carrying amount.

iv. *Exploration costs* other than geological and geophysical costs, excluding the costs of drilling exploration wells and exploration licenses, are recognized as an expense in statement of profit or loss and other comprehensive income when incurred.

v. *Development expenditure* incurred in developing proved reserves and in processing and storing oil and gas (including costs incurred in drilling relating to productive wells and dry wells under development, oil rigs, recovery improvement systems, etc.) are recognized as assets under "*Oil and gas properties*".

vi. *Future field abandonment and dismantling costs* (environmental, safety, etc.) are estimated, on a field-by-field basis, and are capitalized at their present value when they are initially recognized under "*Oil and gas properties*" in assets in the statement of financial position. This capitalization is recorded against the caption "*Asset retirement obligation*" (see Note 18).

The costs capitalized as described above are depreciated as follows:

i. Investments in the acquisition of proven and probable reserves and common facilities are depreciated over the estimated commercial life of the field on the basis of the production for the period as a proportion of the proven and probable reserves.

ii. The costs incurred in surveys for the development and extraction of hydrocarbon reserves are depreciated over the estimated commercial life of the oil field on the basis of the relationship between the production of the period and the total of the proved and probable reserves of the field.

iii. Investments carried out in fields that are in the development or exploitation phase are not depreciated. These investments are tested for impairment at least once a year and whenever indications of impairment are detected.

The changes in estimated reserves are considered on a prospective basis in calculating depreciation.

3.6 Impairment of property, plant and equipment, intangible assets

In order to ascertain whether its assets have become impaired, the Company compares their carrying amount with their recoverable amount at least annually and whenever there are indications that the assets might have become impaired. Recoverable amount is the higher of fair value less costs to sell and value in use. If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized as an expense in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined in case no impairment loss had been recognized for the asset in prior years.

3.7 Sinking funds

The Company contribute to a separate fund established to help fund decommissioning and environmental obligations. The Company recognises its interest in the fund separately from the liability to pay the decommissioning costs. Offsetting is not appropriate unless the Company is not liable to pay decommissioning costs even if the funds fails to pay. The Company does not have control, joint control or significant influence over the fund and therefore, the right to receive assets of the funds are accounted for as a reimbursement of the entity's decommissioning obligation, at the lower of the amount of the decommissioning obligation and the Company's share of the fair value of net assets of the fund.

3.8 Financial assets

Classification

The Company classifies its financial assets at the time it is initially recognised and is subsequently measured at either amortised costs, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL").

The classification of financial asset at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing the financial assets. For assets measured at fair value, gains and losses will either be recorded in profit or loss or other comprehensive income ("OCI"). For investments in equity instruments that are not held for trading, this will depend on whether the Company has made an irrevocable election at the time of initial recognition to account for the equity investment at FVOCI.

The Company reclassifies debt investments when and only when its business model for managing those assets change.

Recognition and initial measurement

At initial recognition, with the exception of trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at FVTPL, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are expensed in profit or loss. Trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient is measured at the transaction price as determined under MFRS 15/IFRS 15.

Financial assets with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

Subsequent measurement

Subsequent measurement of debt instruments depends on the Company's business model for managing the asset and the cash flow characteristics of the asset. There are three measurement categories into which the Company classifies its debt instruments:

a) Debt instruments

i. Amortised cost

Assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortised cost. Interest income from these financial assets is included in finance income using the effective interest rate method. Any gain or loss arising on derecognition of the Company's financial assets are recognised directly in profit or loss and presented in other operating gains/(losses). Impairment losses are presented as separate line item in the statement of profit or loss and other comprehensive income.

ii. FVTPL

Assets that do not meet the criteria for amortised cost or FVOCI are measured at FVTPL. A gain or loss on a debt investment that is subsequently measured at FVTPL is recognised in profit or loss and presented net within other operating gains/(losses) in the period in which it arises.

b) Equity instrument

FVOCI

Assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Movements in the carrying amount are taken through OCI, except for the recognition of impairment gains or losses, interest revenue and foreign exchange gains and losses which are recognised in profit or loss. When the financial asset is derecognised, the cumulative gain or loss previously recognised in OCI is reclassified from equity to profit or loss and recognised in other operating gains/(losses). Interest income from these financial assets is included in finance income using the effective interest rate method. Foreign exchange gains and losses and impairment expenses are presented in other operating gains/(losses). When it is deemed to be material in nature, the impairment expenses shall be presented as separate line item in the statement of profit or loss and other comprehensive income.

Impairment of financial assets

The Company assesses on a forward looking basis the expected credit losses ("ECL") associated with its debt instruments carried at amortised cost. The amount of the expected credit losses is updated at the end of each reporting period to reflect changes in credit risk since initial recognition of the respective financial instrument.

The expected credit losses on these financial assets are estimated using a provision matrix based on the Company's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. For all other financial instruments, the Company recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the Company measures the loss allowance for that financial instrument at an amount equal to 12 month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12 month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

The Company applies the MFRS 9/IFRS 9 simplified approach to measure ECL which uses a lifetime ECL for all trade receivables, see Note 5.2.5 to the financial statements for further details.

Significant increase in credit risk

The Company considers the probability of default upon initial recognition of asset and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. To assess whether there is a significant increase in credit risk, the Company compares the risk of a default occurring on the asset as at the reporting date with the risk of default as at the date of initial recognition. It considers available reasonable and supportable forward looking information that includes historical default rate, internal and external credit rating (as applicable), actual or expected changes in economic and regulatory environment that are expected to cause a significant change to the debtor's ability to meet its obligations.

A significant increase in credit risk is presumed if a debtor become inactive, indication of consistent delay in making contractual payments that are long past due with history of default or the debtor is expected to/or is experiencing significant financial difficulties and cash flow problems.

Derecognition of financial assets

Financial assets are derecognised when the contractual rights to receive cash flows from the financial assets have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Any gain or loss arising on derecognition is recognised directly in profit or loss and presented in other gains/(losses) together with foreign exchange gains and losses.

3.9 Financial liabilities

Classification

Financial liabilities are classified according to the substance of the contractual arrangements entered into and the definitions of a financial liability. Management determines the classification of financial liabilities at initial recognition.

Financial liabilities are recognised in the statements of financial position when, and only when, the Company become a party to the contractual provisions of the financial instrument. The Company classifies all its financial liabilities as other financial liabilities.

Recognition and initial measurement

Trade and other payables are recognised initially at fair value net directly attributable transaction costs and subsequently measured at amortised cost using the effective interest method.

Loans and borrowings are recognised initially at fair value, net of transaction costs incurred and subsequently measured at amortised cost using the effective interest method. Borrowings are classified as current liabilities unless the Company have an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

Derecognition of financial liabilities

A financial liability is derecognised when the obligation under the liability is extinguished. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in the statements of comprehensive income.

3.10 Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when there is a legally enforceable right to offset the recognised amounts and there is an intention to settle on a net basis, or realise the asset and settle the liability simultaneously. The legally enforceable rights must not be contingent on future events and must be enforceable in the normal course of business and in the event of default, insolvency or bankruptcy.

3.11 Cash and cash equivalents

The Company classifies under " *Cash and cash equivalents* " in the statement of financial position liquid financial assets, deposits or financial assets that can be converted into a known amount of cash three months from initiation to maturity and that are subject to an insignificant risk of changes in value.

3.12 Trade and other receivables

Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, where they are recognised at fair value plus transaction costs. Other receivables are recognised initially at fair value plus transaction costsTrade and other receivables are recognised initially at fair value and subsequently measured at amortised costs using the effective interest method, less loss allowance.. The impairment policy for trade receivables is in accordance with that for impairment of financial assets as described in Note 3.8 to the financial statements.

3.13 Provisions and contingent liabilities

In accordance with prevailing accounting standards, the Company makes a distinction between:

a) Provisions: present obligations, either legal or assumed by the Company, arising from past events, the settlement of which is probable to give rise to an outflow of resources the amount and timing of which are uncertain; and

b) Contingent liabilities: possible obligations that arise from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more future events not wholly within the control of the Company, or present obligations arising from past events, the amount of which cannot be measured with sufficient reliability or whose cancellation is not likely to give rise to an outflow of resources embodying future economic benefits.

These provisions are recognized when the liability or obligation giving rise to the indemnity or payment arises, to the extent that its amount can be reliably estimated and it is probable that the commitment will have to be settled.

Contingent liabilities are not recognized as provisions in the financial statements. Notwithstanding the above, whenever it is deemed as non-remote that settlement of such a liability will give rise to an outflow of resources, the existence of these liabilities is disclosed.

3.14 Asset Retirement Obligation ("ARO")

The fair values of the statutory, contractual or legal obligations associated with the retirement and reclamation of tangible long-lived assets are recorded when incurred and when a reasonable estimate of this amount can be made, with a corresponding increase to the carrying amount of the related assets. The increase to capitalised costs is amortised to profit and loss on a basis consistent with the depreciation, depletion and amortisation of the underlying assets. Subsequent changes in the estimated fair value of the ARO are capitalised and amortised over the remaining useful of the underlying asset.

The ARO liabilities are carried on the statement of financial position at their discounted present value and are accreted over time for the change in their present value, with this accretion charge recognised in profit and loss.

Actual expenditure incurred are charged against the accumulated obligation. Any difference between the recorded ARO and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

3.15 Revenues and expenses recognition

Revenue associated with the sale of crude oil and natural gas are recognised when control of the goods has transferred, being at the point the crude oil and natural gas exiting from the Company's storage tanks into the customer's storage tank.

Revenue from the sale of crude oil and natural gas are recognised based on the price in the agreement, that is the market price. Each of the field produces its own oil into distinctive tanks, and hence the benefit is derived from the lifted oil of the specific tanks distinctively and each lifting of entitled oil is a separate and distinctive performance obligation on its own as the benefits are directly derived from selling this.

Crude oil produced and sold by the Company below or above its working interest share in the related resource properties, results in production under-lifting or over-lifting.

The Company has adopted the entitlement method in measuring the under-lifting and over-lifting whereby they were measured at the fair value. Under-lifting is recorded as part of the *"Trade and other receivables"* in the statement of financial position and *"Change in underlift"* in the statement of profit and loss and other comprehensive income. Over-lifting is recorded as part of the *"Trade and other payables"* in the statement of financial position and presented as *"Supplies"* in the statement of profit or loss, along with purchases made during the year.

Under-lifting is reversed when the crude oil is lifted and sold, with the sales proceeds recorded as revenue and the cost of the inventory expensed. Over-lifting is reversed when sufficient volumes are produced to make up the overlifted volume.

The Company's operations are governed by the PSC. Under the PSC, revenues are derived from cost recovery oil and gas and profit oil and gas. Generally, cost recovery oil and gas allows the Company to recover its capital and production costs and, as appropriate, the costs carried by the Company on behalf of relevant national oil company from production. Profit oil and gas is allocated to the national oil company and contract parties in accordance with the terms of the respective PSCs.

Interest income is accrued on a time proportion basis, by reference to the principal outstanding and the effective interest rate applicable.

An expense is recognized when there is a decrease of economic benefits associated to a reduction of an asset, or an increase in a liability, whichever can be measured reliably.

3.16 Financing costs

Financing costs comprise interest payable on borrowings and any accretion in provision due to the passage of time.

3.17 Income Tax

The Company recognizes in the statement of profit or loss and other comprehensive income for the year the accrued tax on the Company's income, which is calculated taking into account the differences between the timing of recognition for accounting purposes and tax purposes of the transactions and other events in the current year recognized in the financial statements, giving rise to temporary differences and, therefore, to the recognition of certain deferred tax assets and liabilities in the statement of financial position. These amounts are recognized by applying to the temporary differences the tax rate that is expected to apply in the period when the asset is realized, or the liability is settled.

Taxation on profit for the year is calculated at the current tax rate based on the estimated chargeable income for the year computed under the Petroleum (Income Tax) Act, 1967 ("PITA"), Income Tax Act, 1967 and Income Tax Act Cap. 73.

Deferred tax liabilities are recognized for all taxable temporary differences, unless the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets recognized for temporary differences and other deferred tax assets (tax losses and tax deductions carry forwards) are recognized when it is considered probable that the Company will have sufficient taxable profits in the future against which the deferred tax asset can be utilized. Deferred tax assets relating to the carry forward of unused tax losses are recognised to the extent that it is probable that future taxable profit will be earned against which the unused tax losses can be utilised.

The accrued income tax expense includes both the deferred income tax expense and the current income tax expense, which is taken to be the amount payable (or refundable) in relation to the taxable net income for the year (see Note 21).

"*Income tax expense*" in the statement of profit or loss and other comprehensive income includes both the accrued income tax expense and the net provisions recognized in the year for uncertain tax position, insofar as the latter relate to income tax.

Current and deferred taxes are recognized outside statement of profit or loss and other comprehensive income if they are related to items that are recognized outside the statement of profit or loss and other comprehensive income. Those entries related to items recognized under "Adjustments for changes in value" are recognized under that heading and those recognized directly in equity are recognized within the equity.

3.18 Foreign Currency

The Company's functional and presentation currency is United States dollars. Transactions in currencies other than the functional currency are deemed to be 'foreign currency transactions' and are translated to the functional currency by applying the exchange rates prevailing at the date of the transaction. At each year end, the foreign currency monetary items on the statement of financial position are measured applying the exchange rate prevailing at that date and the exchange rate differences arising from such measurement are recorded as "foreign exchange gain/(loss)" within "Financial result" in the statement of profit or loss and other comprehensive income in the year incurred.

3.19 Leases

A lease is an agreement whereby the lessor conveys to the lessee in return for a payment, or series of payments, the right to use an asset for an agreed period of time.

a) Leases in which the Company is a lessee

From January 1, 2019, leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company (i.e. the commencement date).

Leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company (i.e. the commencement date).

Lease terms

In determining the lease term, the Company considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not to be terminated).

The Company reassess the lease term upon the occurrence of a significant event or change in circumstances that is within the control of the Company and affects whether the Company is reasonably certain to exercise an option not previously included in the determination of lease term, or not to exercise an option previously included in the determination of lease term. A revision in lease term results in re-measurement of the lease liabilities.

ROU assets

ROU assets are initially measured at cost comprising the following:

- The amount of the initial measurement of lease liability;
- Any lease payments made at or before the commencement date less any lease incentive received;
- Any initial direct costs; and
- Decommissioning or restoration costs.

Upon lease commencement, the Company measures the ROU asset using a cost model. ROU assets are depreciated over the lease term on a straight-line basis.

Lease liabilities

Lease liabilities are initially measured at the present value of the lease payments that are not paid at that date. The lease payments include the following:

- Fixed payments (including in-substance fixed payments), less any lease incentive receivable;
- The exercise price of an extension options if the Company is reasonably certain to exercise that option; and
- Payments of penalties for terminating the lease, if the lease term reflects the Company exercising that option.

Lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be readily determined for leases in the Company, the Company's incremental borrowing is used. This is the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the ROU in a similar economic environment with similar term, security and conditions.

Lease payments are allocated between principal and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

The Company presents the lease liabilities as a separate line item in the statement of financial position. Interest expense on the lease liability is presented within the finance cost in the statement of profit or loss and other comprehensive income.

Reassessment of lease liabilities

The Company is exposed to potential cash flows change if there is a change in lease term due to the Company exercises an extension or termination option, which are not included in the lease liability until the Company is reasonably certain to exercise the option.

When the option is exercised, the lease liabilities are remeasured by discounting the revised lease payments using revised discount rate.

Short-term leases and leases of low-value assets

Short-term leases are leases with a lease term of 12 months or less. Low-value assets comprise IT equipment, small items of office furniture and vehicles. Payment associated with short-terms lease of equipment, vehicles and vessels and all leases of low-value assets are recognised on a straight-line basis as an expense in the statement of profit or loss and other comprehensive income.

Until December 31, 2018, a lease is recognised as a finance lease if it transfers substantially to the Company all the risks and rewards incident to ownership. All leases that do not transfer substantially all the risk and rewards are classified as operating leases.

Finance leases

Assets acquired by way of finance leases are stated at an amount equal to the lower of their fair values and the present value of the minimum lease payments at the inception of the leases, less accumulated depreciation and impairment losses. The corresponding liability is included in the statement of financial position as part of "*Trade and other payables*" for current portion and "*Long-term lease obligation*" for non-current portion. In calculating the present value of the minimum lease payments, the discount factor used is the interest rate implicit in the lease, when it is practicable to determine; otherwise, the Company's incremental borrowing rate is used.

Lease payments are apportioned between the finance charges and the reduction of the outstanding liability. Finance costs, which represent the difference between the total leasing commitments and the fair value of the assets acquired, are recognised as finance expenses in the statement of comprehensive income over the term of the relevant lease so as to produce a constant periodic rate of charge on the remaining balance of the obligations for each accounting period.

The depreciation policy for capital lease is in accordance with that for depletion, depreciation and amortisation as described in Note 3.5.

Operating leases

Leases where substantially all the rewards and risks of ownership of assets remain with the lessor are accounted for as operating leases. Rental on operating leases are charged to profit or loss on a straight line basis in the financial year in which they are incurred.

3.20 Inventories

Inventories are valued at the lower of cost less provision for obsolescence and net realisable value. The cost is calculated as average cost, and includes the acquisition costs after deduction of any discounts, rebates or other similar items, such as interest incorporated into the nominal amount, plus any additional costs incurred to bring the goods to a saleable condition, such as transport, import duties, insurance and other costs directly attributable to the acquisition of inventories. The inventories of the Company are the Company's share of purchased materials held under the joint operations agreements for utilisation in conducting the affairs of the joint operations.

The Company carries out annual material review of inventories at the end of the year, recording the appropriate value correction with a charge to results when inventories are obsolete and no foreseeable future usage. When the circumstances that previously caused the value correction cease to exist, the amount is reversed.

3.21 Transactions with related parties

The Company performs all its operations with related parties at agreed terms and prices, which is why management considers that there are no significant risks from this aspect from which future liabilities may arise.

3.22 Joint Operation Agreements

The Company recognises its share of jointly controlled assets and jointly incurred liabilities on the basis of the percentage of ownership, as well as jointly controlled assets and liabilities incurred as a result of the joint operation agreements.

The Company recognises the proportion of income generated and expenses incurred under the joint operation agreement in the statement of profit or loss and other comprehensive income, in addition to the expenses incurred in relation to the interest in the joint operation.

4. New accounting policies

4.1 MFRS 16/IFRS 16 Leases

The Company has applied MFRS 16/IFRS 16 with the date of initial application of January 1, 2019 by applying the simplified retrospective transition method.

Under the simplified retrospective transition method, the 2018 comparative information was not restated and cumulative effects of initial application of MFRS 16/IFRS 16 where the Company is lessee were recognised as an adjustment to the opening balance of retained earnings as at January 1, 2019. The comparative information continued to be reported under the previous accounting policies governed under MFRS 117/IAS 17 'Leases' and IFRIC 4 'Determining whether an Arrangement Contains a Lease'.

In addition, the Company has elected not to reassess whether a contract is, or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date, the Company relies on its assessment made applying MFRS/IAS 17 117 and IFRIC 4.

The new accounting policies are disclosed in Note 3.19.

On adoption of MFRS 16/IFRS 16, the Company recognised lease liabilities in relation to leases which had been previously classified as 'operating leases' under the principle of MFRS 117/IAS 17 Lease. These liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate as of January 1, 2019.

The associated right-of-use ("ROU") assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognised in the statement of financial position as at December 31, 2018.

In applying MFRS 16/IFRS 16 for the first time, the Company has applied the following practical expedients permitted by the standard to leases previously classified as operating leases under MFRS 117/IAS 17:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- reliance on previous assessments on whether leases are onerous;
- the accounting for operating leases with a remaining lease term of less than 12 months as at January 1, 2019 as short-term leases;
- the exclusion of initial direct costs for the measurement of the ROU asset at the DIA; and
- the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

For leases previously classified as finance leases and presented as part of 'property, plant and equipment', the Company recognised the carrying amount of the lease assets and lease liability immediately before transition as the carrying amount of the ROU asset and the lease obligation at the date of initial application ("DIA").

Measurement of lease obligation on January 1, 2019

The weighted average lessee's incremental borrowing rate applied to the lease liabilities on January 1, 2019 was 5.12% per annum for USD contracts and 9.60% per annum for MYR contracts.

The reconciliation between operating lease commitments disclosed applying MFRS 117/IAS 17 at December 31, 2018 to the lease liabilities recognised at January 1, 2019 is as follows:

	USD'000
Operating lease commitments disclosed as at December 31, 2018	9,743
Discounted using the lessee's incremental borrowing rate of at the DIA	8,283
Add:	
Finance lease liabilities recognised as at December 31, 2018	13,720
Lease obligation recognised as at January 1, 2019	22,003
Of which are:	
Current lease obligation	3,278
Non-current lease obligation	18,725
	22,003

The effect of the changes in the accounting policies on the line items are as follows:

	USD'000 As previously report as at December 31, 2018	USD'000 MFRS 16/IFRS 16 adjustment	USD'000 As re-measured as at January 1, 2019
Statement of financial position (extract) As at January 1, 2019			
Property, plant and equipment	117,911	(11,121)	106,790
Right-of-use assets	-	19,208	19,208
Retained earnings	(20,503)	196	(20,307)
Long-term lease obligation	(11,654)	(7,071)	(18,725)
Trade and other payables	(2,984)	(1,212)	(4,196)

4.2 IFRIC 23 Uncertainty over income tax treatments

The Company has applied the IFRIC 23 that clarifies the accounting for uncertainties in income taxes, effective for annual periods beginning on or after 1 January 2019.

The interpretation is to be applied to the determination of taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates, when there is uncertainty over income tax treatments under MFRS 112/IAS 12.

An entity has to consider whether it is probable that the relevant authority will accept each tax treatment, or group of tax treatments, that it used or plans to use in its income tax filing.

If the entity concludes that it is probable that a particular tax treatment is accepted, the entity has to determine taxable profit (tax loss), tax bases, unused tax losses, unused tax credits or tax rates consistently with the tax treatment included in its income tax filings. If the entity concludes that it is not probable that a particular tax treatment is accepted, the entity has to use the most likely amount or the expected value of the tax treatment when determining taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates. The decision should be based on which method provides better predictions of the resolution of the uncertainty.

During the financial year 2019, a provision of $7,387 thousand is made for uncertain tax position of the Company in relation to the Petroleum (Income Tax) Act, 1967 ("PITA") on the deductibility of certain expenses.

The amount of tax provision is measured based on "most likely amount" method. The PITA provision is made in accordance to the Notice of Additional Assessment ("NoAA") received from Inland Revenue Broad ("IRB") of Malaysia for Year Assessment ("YA") 2014.

Due to the uncertainty associated with such tax items, there is a possibility that, on conclusion of open tax matters at a future date, the final outcome may differ significantly.

5. Critical accounting judgments and key sources of estimation uncertainty

5.1 Critical judgements in applying the Company's accounting policies

In the process of applying the Company's accounting policies, which are described in Note 3 above, management is of the opinion that there are no instances of application of judgement which are expected to have a significant effect on the amounts recognised in the financial statements.

5.2 Key sources of estimation uncertainty

The information included in these financial statements is the responsibility of the management of the Company.

In the financial statements for the year 2020, 2019 and 2018 on occasions estimations made by the management of the Company have been used to evaluate some of the assets, liabilities, income, expenses and commitments that are recorded in the accounts. Basically, those estimations, made according to the best information available, relate to:

- Assessment of potential impairment losses on certain assets
- Estimation of crude oil and gas reserves and resources
- Provisions for litigation, dismantling and other contingencies
- Calculation of income tax, tax credit and deferred tax assets
- Calculation of expected credit loss
- Extension and termination options
- Allowance for inventories obsolescence

5.2.1 Assessment of potential impairment losses on certain assets

In order to ascertain whether its assets have become impaired, the Company compares the carrying amount with the recoverable amount at least annually and whenever there are indications that an asset might have become impaired ("impairment test"). If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

On the occurrence of new events, or changes in existing circumstances, which prove that an impairment loss recognized on a prior date no longer exists or has decreased, a new estimate of the recoverable value of the corresponding asset is developed, to determine whether it is appropriate to reverse the impairment losses recognized in previous periods.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized for the asset in prior years.

For the "impairment test", assets are grouped into cash-generating units (CGUs), to the extent that such assets, when individually considered, do not generate cash inflows that are independent of the cash inflows from other assets or CGUs. The grouping of assets into the various CGUs requires the use of professional judgments and the determination, among other criteria, of the business segments and geographic areas in which the Company operates. In the upstream segment, each CGU corresponds to one of the various contractual exploration areas widely known as "blocks" exceptionally, if the cash flows generated by more than one block are mutually interdependent, those blocks will be grouped into a single CGU. The recoverable amount is the higher of fair value less costs of sale and value in use.

The methodology used by the Group to estimate the recoverable amount of assets is, in general, the value in use calculated by discounting to present value the future cash flows expected to be derived from the operation of these assets.

The cash flow projections are based on the best available estimates of the CGUs' income and expenses using sector forecasts, prior results and the outlook for the business's performance and market's development:

- Macroeconomic variables are those used in the preparation of the budgets. The macroeconomic framework for the countries in which the Group operates takes into consideration variables such as inflation, GDP, exchange rate, etc. and is prepared on the basis of the content of internal reports that use in-house estimates, based on updated external information of relevance (forecasts prepared by consultants and specialized entities).

- The oil and natural gas price paths used for the impairment test are our own estimates, although they are consistent or in line with the view of prices established by the various international benchmark agencies, including the International Energy Agency ("IEA"). The paths are developed on the basis of available macroeconomic, financial and market information and the forecasts provided by analysts and they consider scenarios for the energy transition and decarbonisation of the economy that are consistent with the commitments assumed to achieve the objectives of the Paris Climate Summit.

In particular, crude oil and gas prices are calculated by analysing key market variables and their foreseeable trend, including our own forecasts of the balance of supply and demand of energy and prices. The longer-term vision is also explained by monitoring other variables such as: the decline, the current CAPEX, the financial sustainability of companies in the sector to certain price environments, and the dynamics in OPEC countries in terms of fiscal sustainability. Econometric models of prices are made with all these elements, which are compared with both public and private external forecasts.

i. To estimate near-term price trends, we basically use forecast reports produced by a selection of, investment banks, macro consultants and international benchmark agencies are taken into account.

ii. The sources that present a sufficiently detailed analysis of long-term forecasts are the macro consultants and benchmark agencies (IEA and EIA), which also carry out detailed studies of supply, demand and price forecasts under different scenarios

The assumptions for the main price references for 2018 are as follows:

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Brent ($/ barrel)	65	70	75	81	86	89	92	94	97

The assumptions for the main price references for 2019 are as follows:

	2020	2021	2022	2023	2024	2025	2026-2027
Brent ($/ barrel)	65	69	70	71	72	74	81

In 2020, in view of the situation in the commodity markets and in particular the social and economic consequences of the COVID-19 pandemic and the foreseeable development of the energy transition, the Group reviewed its expectations of future oil and gas prices, modifying the price paths defined at the end of 2019 to bring them into line with the new scenario.

It should be noted that these estimates were made in an environment of high uncertainty, marked by the scenarios of emerging from the COVID-19 crisis, by the dynamics of the energy transition and decarbonisation of the economy and, in short, by their possible impacts on the Oil & Gas markets.

- The Brent's path was revised downwards in the short and medium term (until 2024) as a result of a contraction in the demand for oil never seen before and a reaction of supply that was insufficient to adjust to the low demand, despite the fact that the OPEC+ made the biggest production cut in its history and other producers have also taken heavy cuts.

- The Henry Hub path was revised upwards for 2021, due to the drop in gas production and the boost in the demand for gas for the electricity industry and electricity generation in the US, and the path was revised downwards in the medium and long term due to the expectation of greater penetration of renewable energies on a global scale and the consolidation of excess supply in the face of falling global demand.

The assumptions for the main price references are as follows:

	2021	2022	2023	2024	2025	2026-2027
Brent ($/ barrel)	49	55	58	62	67	59

Future cash flows are discounted to their present value at a specific rate for each CGU, determined based on the currency of its cash flows and the risks associated with them. The discount rate used by the Company is the weighted average cost of capital employed for each country and business.

Cash flows are estimated on the basis of the outlook for their key variables in accordance with the expectations reflected in the annual budget and in the strategic plans for each business, in line with the new scenario of energy transition and decarbonization of the economy.

The discount rates used in 2020, 2019 and 2018 are as follows:

2020	2019	2018
7.36%	7.62%	8.16%

Valuations of the production assets of Exploration and Production (Upstream) use cash flow projections for a period that covers the economically productive useful lives of the oil and gas fields, limited by the contractual expiration of the operating permits, agreements or contracts. The general principles applied to determine the variables that most affect the cash flows of this business are described below:

- Oil and gas sales prices. The international benchmark price used by the Group is Brent.

- Reserves, resources and production profiles. Production profiles are estimated on the basis of output levels at existing wells and the development plans in place for each productive field. As a consequence, these profiles are then used to estimate proved and unproved reserves and resources.

- Operating expenses and capital expenditure. These are calculated for the first year on the basis of the Group's annual budget and thereafter in keeping with the asset development programs, applying an escalation factor for operating expenses and investments basically of -1% to 1% (1% to 1.5% in 2019).

5.2.2 Estimation of crude oil and gas reserves and resources

The process of estimating oil and gas reserves is a key component of the Company's decision-making process. Oil and gas reserve estimates are used to calculate depreciation and amortization charges applying the unit-of-production ratio method and to assess the recoverability of the investments in the assets. Changes in reserve and resources could have a significant impact on the result.

The reserves are classified as follows:

a. Proved reserves: Proved reserves are those quantities of crude oil, natural gas and natural gas liquids that, with the information available to date, are estimated to be recoverable with reasonable certainty. There should be at least a 90% probability that the amounts recovered will equal or exceed the 1P estimate.

b. Probable reserves: Probable reserves are those additional reserves that, together with proved reserves, make up scenario 2P. There should be at least a 50% probability that the amounts recovered will equal or exceed the 2P estimate. This scenario reflects the best estimate of the reserves.

c. Developed reserves: Proved or probable quantities that are expected to be recovered from existing wells and facilities.

d. Undeveloped reserves: Proved or probable quantities that are expected to be recovered through future investments.

To estimate oil and gas reserves and resources, the Company uses the criteria established by the "SPE/WPC/AAPG/SPEE/SEG/ SPWLA/EAGE Petroleum Resources Management System", commonly referred to by its acronym SPE-PRMS (SPE standing for Society of Petroleum Engineers).

5.2.3 Provisions for litigation, dismantling and other contingencies

The Company makes judgements and estimates that affect the recognition and measurement of provisions for litigation, decommissioning and other contingencies. The final cost of settling complaints, claims and lawsuits may vary due to differences in the identification of dates, interpretation of rules, technical opinions and assessments of the amount of damages and liabilities.

The calculations to recognize provisions for the cost of decommissioning its oil and gas production operations are complex, on account of the need to initially recognize the present value of the estimated future costs and to adjust this figure in subsequent years in order to reflect the passage of time and changes in the estimates due to changes in the underlying assumptions used as a result of technological advances and regulatory changes, economic, political and environmental security factors, as well as changes in the initially-established schedules or other terms. The decommissioning provisions are updated regularly to reflect trends in estimated costs and the discount rates. These discount rates take into account the risk-free rate, by term and currency, country risk and the cash flow projection period. Specifically, the weighted average rate set by the Company was 2.36% (2019: 3.19%, 2018: 4.70%).

Additionally, the Company makes judgments and estimates in recording costs and establishing provisions for environmental clean-up and remediation costs, which are based on current information regarding costs and expected plans for remediation based on applicable laws and regulations, the identification and assessment of the effects on the environment, as well as sanitation technologies.

Therefore, any change in the factors or circumstances related to provisions of this nature, as well as changes in laws and regulations could, as a consequence, have a significant effect on the provisions recognized for these costs.

5.2.4 Calculation of income tax, tax credit and deferred tax assets

The appropriate assessment of the income tax expense is dependent on several factors, including estimates of the timing and realization of deferred tax assets and the timing of income tax payments. Collections and payments may be materially different from these estimates as a result of changes in the expected performance of the Company's businesses or in tax regulations or their interpretation, as well as unforeseen future transactions that impact the Company's tax balances.

During the current financial year, a provision of is $35,186 thousand made for uncertain tax position of the Company in relation to the Petroleum (Income Tax) Act, 1967 ("PITA") on the deductibility of certain expenses and the Income Tax Act, 1967 ("CITA") on taxability of other income.

The amount of tax provision is measured based on "most likely amount" method. The PITA provision is made in accordance to the Notice of Assessment ("NoA") received from Inland Revenue Board ("IRB") of Malaysia for YAs 2015 and 2016 and estimation of the derived impacts in the subsequent YAs up to 2020. The CITA provision covers potential CITA tax and penalties on the YAs open for review by the IRB.

The tax matters on PITA are in the process of legal proceedings and the cases had been discussed in High Court. The High Court had granted the Company with an order of prohibition until the case is being decided in the Special Commissioners of Petroleum Income Tax ("SCPIT"). The Company is currently waiting for responses from SCPIT.

In relation to the tax matters on CITA, the Company had made an appeal via Form Q to the IRB against the Notices of Additional Assessment for YA2015 issued by IRB on January 29, 2021. The IRB had in its reply insisted that the additional assessment was correct and the Company is currently discussing with its legal counsel on the next action plan.

Due to the uncertainty associated with such tax items, there is a possibility that, on conclusion of open tax matters at a future date, the final outcome may differ significantly.

Deferred tax assets are only recognized when it is considered probable that the Company will have sufficient taxable income in the future against which they can be utilized.

Deferred tax assets are reviewed when there are indications of impairment, and in any event once a year, to verify that they still qualify for recognition and they are considered to be recoverable in the future, and the appropriate adjustments are made on the basis of the outcome of the analyses performed. These analyses are based on: (i) assumptions made to analyse the existence or otherwise of sufficient future earnings for tax purposes that might offset the tax losses or apply existing tax credits, based on the approach used to ascertain the presence of indications of impairment on its assets; (ii) the assessment of earnings estimates for the Company in accordance with the Company's business plans and the Group's overall strategic plan; and (iii) the statute of limitations period and other utilization limits imposed under prevailing legislation in the country for the recovery of the tax credits.

5.2.5 Calculation of expected credit loss

The Company has adopted the simplified expected credit loss model for its trade receivable, having its own risk assessment models for its customers and estimating the expected loss based on the probability of default, the balance at risk and estimated loss given default and taking into account the available information of each customer.

The remaining financial assets are individually monitored.

As a general criterion, 180 days past due is used to define credit-impaired financial instruments (in the absence of other evidence of default such as bankruptcy, etc).

The expected credit loss on financial instruments is calculated based on the stage of the debtor's credit risk statement.

- Phase 1: At the time of initial recognition, the expected credit loss is calculated with the probability of default in the first 12 months. In the case of trade receivables, the calculation is spread over the life of the instrument, in accordance with the accounting standard.
- Phase 2: When the instrument undergoes a significant increase in risk, the expected loss is calculated with the probability of default for the entire life of the instruments.
- Phase 3: When the instrument is already impaired, the expected loss for the entire life of the instrument is calculated and, in the event that interest accrues, it is calculated on the net balance of the provision of credit loss.

The assessment of the impairment of the value of the financial assets, to which the expected loss model is applicable, is calculated according to the following formula:

Expected credit loss = Probability of default x Exposure x Severity

Probability of default is calculated individually for each trade debtor according to the solvency models approved by the Repsol Group, except for individuals, from whom an average default rate is used. The models take into account quantitative information (economic-financial variables of the customer, external and internal payment behaviour, etc.), quantitative information (sector of activity, macroeconomic data on the country, etc.) and market sensitivity variables (e.g. price evolution). An internal rating and an associated probability of default are obtained for each debtor, according to the models.

Exposure is calculated taking into account the total amount of outstanding credit and a potential future exposure according to the available risk limit.

Severity reflects the percentage of unrecovered exposure in the event of default, taking into account whether or not such exposure is guaranteed, and is based on the behaviours of customers.

5.2.6 Extension and termination options

In determining the lease term, management considers all facts and circumstances that create an economic incentive to exercise an extension option or not to exercise a termination option. Extension options or periods after termination options are only included in the lease term if the lease is reasonably certain to be extended or not terminated. The Company considers historical lease durations in determining whether to exercise the extension option.

As at 31 December 2019, potential future cash outflows of $321 thousand (undiscounted) have not been included in the lease liability because it is not reasonably certain that the leases will be extended and this lease with extension option was subsequently terminated in 2020. As at 31 December 2020, all the leases with extension options have been included in the lease liabilities.

5.2.7 Allowance for inventories obsolescence

At the end of financial year, the Company reviews the carrying amount of the inventories to ensure that they are stated at the lower of cost and net realisable value. In assessing net realisable value and making appropriate allowances, management identifies inventories that are slow-moving and consider the inventories' physical conditions, market conditions and market price for similar items.

6. Risk management

The Company is exposed to various risks that are particular to its core business of exploration, development and production. These risks arise in the normal course of the Company's business.

The Company's goal in risk management are to ensure that management understands, measures and monitors the various risks that arise in connection with their operations. Policies and guidelines have been developed to identify, analyse, appraise and monitor the dynamic risks facing the Company. Based on this assessment, each business unit adopts appropriate measures to mitigate these risks in accordance with the business unit's view of the balance between risk and reward.

The Company has exposure to foreign exchange risk, liquidity risk, credit risk, commodity price risk and interest rate risk arising from its use of financial instruments in the normal course of the Company's businesses.

6.1 Foreign exchange risk

The Company is exposed to currency risk as a result of the foreign currency transactions entered into by the Company in currencies other than its functional currency.

The net unhedged financial liabilities and assets of the Company that are not denominated in its functional currency at the reporting date are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Ringgit Malaysia (MYR):			
Due from related parties	-	-	27
Cash and cash equivalents	906	1,831	79
Trade and other payables	(73)	(78)	(83)
Lease obligation	(462)	(735)	-
Total	**371**	**1,018**	**23**
Euro (EUR):			
Trade and other payables	-	-	(5)
Due to related parties	(5)	(3)	-
Total	**(5)**	**(3)**	**(5)**

Sensitivity analysis for foreign currency risk

The Company is mainly exposed to the currency of MYR, the exposure to EUR is deemed as not significant.

The following table details the Company's sensitivity to a two per cent increase and decrease in functional currency against the relevant foreign currencies. Two per cent is the sensitivity rate used when reporting foreign currency risk internally to key management personnel and represents management's assessment of the reasonably possible change in foreign exchange rates. A positive number below indicates an increase in profit net of tax where functional currency strengthens two per cent against the relevant foreign currency. For a two per cent weakening of functional currency against the relevant foreign currency, there would be a comparable impact on net profit after tax, and the balances below would be negative.

	USD'000 2020	USD'000 2019	USD'000 2018*
USD/MYR:			
- strengthened 2% (2019: 2%, 2018: 2%)	(4)	(12)	(1)
- weakened 2% (2019: 2%, 2018: 2%)	4	12	1

* less than $1 thousand

6.2 Liquidity risk

The Company incurred a loss of $53,161 thousand for the financial year ended December 31, 2020. The Company's current liabilities exceeded its current assets by $49,495 thousand ($27,423 thousand in 2019, $26,705 thousand in 2018) as at reporting date. These factors raise doubt that the Company will be able to continue as a going concern. Based on the projected cashflows prepared by management, the Company will have sufficient cash flows for the next twelve months from the date of the financial statements to meet their cash flow requirements. Therefore, the Company has prepared the financial statements on a going concern basis.

The Company actively manages its operating cash flows and the availability of funding to ensure that all refinancing, repayment and funding needs are met. As part of its overall prudent liquidity management, the Company maintains sufficient levels of cash to meet its working capital requirements.

The table below summarises the maturity profile of the Company's financial liabilities at the reporting date based on contractual undiscounted repayment obligations:

	USD'000 Less than one year	USD'000 From one to five years	USD'000 More than five years	USD'000 Total
2018				
Lease obligation	2,066	8,444	6,894	17,404
Loans from related parties	41,980	-	-	41,980
Trade and other payables	254	10,414	-	10,668
Total	**44,300**	**18,858**	**6,894**	**70,052**
2019				
Lease obligation	2,537	12,439	8,858	23,834
Due to related parties	12	-	-	12
Loans from related parties	16,837	-	-	16,837
Trade and other payables	21,671	-	-	21,671
Total	**41,057**	**12,439**	**8,858**	**62,354**
2020				
Lease obligation	2,661	12,423	5,403	20,487
Due to related parties	5	-	-	5
Loans from related parties	18,343	-	-	18,343
Trade and other payables	5,199	-	-	5,199
Total	**26,208**	**12,423**	**5,403**	**44,034**

6.3 Credit risk

Credit risks, or the risk of counterparties defaulting, are controlled by the application of credit approvals, limits and monitoring procedures. The Company is exposed to credit risk, which is the risk that a customer or counterparty will fail to perform an obligation or settle a liability, resulting in credit loss to the Company. The Company's concentration of credit risk is mitigated by dealing with generally credit worthy large international oil and gas companies.

The Company minimises credit risk by entering into contracts with highly credit rated counterparties. Potential counterparties are subject to credit assessment and approval prior to any transaction being concluded and existing counterparties are subject to regular reviews, including re-appraisal and approval of granted limits. The creditworthiness of counterparties is assessed based on an analysis of all available quantitative and qualitative data regarding business risks and financial standing, together with the review of any relevant third party and market information. Reports are regularly prepared and presented to management that cover the Company's overall credit exposure against limits and securities, exposure by segment and overall quality of portfolio.

The maximum exposure to credit risk for the Company is represented by the carrying amount of each financial asset.

A significant portion of these receivables are regular customers that have been transacting with the Company.

The Company uses ageing analysis and credit term review to monitor the credit quality of the receivables. Any customers exceeding their credit limit are monitored closely.

The Company determines the expected credit losses on trade receivable by using individual assessment, estimated based on historical credit loss experience of each individual receivable based on the past status of the adjusted as appropriate to reflect current conditions and estimates of future economic conditions. Accordingly, the credit risk profile of the trade receivables is presented based on their past due status.

For bank and financial institutions, only independently rated parties with minimum rating of above "A-" are accepted.

The following shows the movement in expected credit loss that has been recognised for trade and other receivables:

	USD'000 2020	USD'000 2019	USD'000 2018
Balance, beginning of year	10	58	7
Movement during the year	(9)	(10)	51
Balance, end of year	**1**	**48**	**58**

The Company's exposure to credit risk, according to the type of financial instrument together with the impairment recognized at December 31 for each of them, is broken down as follows:

2020	USD'000 Gross	USD'000 Impairment	USD'000 Net
Trade receivables	4,943	(1)	4,942
Cash and cash equivalents	939	-	939
Total	**5,882**	**(1)**	**5,881**
2019			
Trade receivables	3,696	(10)	3,686
Cash and cash equivalents	5,790	-	5,790
Total	**9,486**	**(10)**	**9,476**
2018			
Trade receivables	6,731	(58)	6,673
Due from related parties	27	-	27
Cash and cash equivalents	4,660	-	4,660
Total	**11,418**	**(58)**	**11,360**

The expected credit loss for amounts due from related parties, cash and cash equivalents at December 31, 2020, 2019 and 2018 are immaterial.

The trade and other receivables shown on the statement of financial position as at December 31, 2020, December 31, 2019 and December 31, 2018 net of loss allowance for impairment are not due as at year-end.

6.4 Commodity price risk

As a result of the development of operations and commercial activities, the Company's results are exposed to the volatility of the prices of oil, natural gas and their derivatives.

The Company monitors its exposure to market risk in terms of sensitivities. These are supplemented by other risk measures on those occasions when the nature of the risk positions requires so.

6.5 Interest rate risk

The Company's primary interest rate risk relates to floating rate interest bearing borrowings. The Company manages its interest rate risk exposure on a transactional basis to achieve cheaper funding in a low interest rate environment and achieve a certain level of protection against rate hikes.

The movement in interest rates would not have any significant impact to the post-tax loss for the financial year.

6.6 Other risk

On March 11, 2020, the World Health Organization raised to the status of global pandemic the public health emergency caused by SARS-CoV-2 virus (commonly known as coronavirus, while COVID-19 denotes the disease caused by the virus). The rapid spread of COVID-19, on an international scale, has triggered an unprecedented healthcare, social and economic crisis that continues to evolve.

The economic impact of the pandemic, combined with pre-existing complications on the supply and demand side, has resulted in an exceptionally challenging pricing environment for oil and gas.

Even amid these difficult circumstances, the Company has sustained the safe operation of its business.

It is difficult to predict to what extent and for how long the impact of the pandemic will affect the Company's business in the future. The lower global demand for crude oil, gas and oil products as a result of the reduction in economic activity and, in particular, the restrictions to mobility, may have a negative impact on prices, production levels and sales volumes, the deterioration of global financial conditions may affect the cost of capital, liquidity or solvency on our customers and partners in joint operations, and so on.

7. Financial Instruments

All the financial assets and financial liabilities of Company are measured at amortised costs. The following table analyses the financial assets and financial liabilities in the statement of financial position by the class of financial instruments to which they are assigned, and therefore by the measurement basis:

7.1 Classification of financial instruments

	USD'000 2020	USD'000 2019	USD'000 2018
Financial assets			
Amortised cost:			
Trade and other receivables	4,942	3,686	6,673
Due from related parties	-	-	27
Cash and cash equivalents	939	5,790	4,660
Total	**5,881**	**9,476**	**11,360**
Financial liabilities			
Amortised cost:			
Lease obligation	16,937	19,499	13,720
Due to related parties	5	12	-
Loans from related parties	18,216	16,637	41,385
Trade and other payables	5,199	21,671	10,202
Total	**40,357**	**57,819**	**65,307**

8. Capital risk management

Capital management is defined as the process of managing the composition of the Company's debts.

The Company operates within clearly defined guidelines that are approved by Repsol, S.A., which is the ultimate holding company and it relies on the ultimate holding company for funding to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities as and when they fall due.

9. Intangible assets

	USD'000 Total
Cost	
Balance at January 1, 2018	223
Additions	16
Change in estimates	(73)
Balance at December 31, 2018	**166**
Additions	337
Balance at December 31, 2019	**503**
Additions	44
Balance at December 31, 2020	**547**
Amortization	
Balance at January 1, 2018	-
Charge for the year	13
Balance at December 31, 2018	**13**
Charge for the year	79
Balance at December 31, 2019	**92**
Charge for the year	133
Balance at December 31, 2020	**225**
Net book value	
Balance at December 31, 2018	**153**
Balance at December 31, 2019	**411**
Balance at December 31, 2020	**322**

The intangible assets mainly consist of the implementation cost of the SAP Project One.

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10. Property, plant and equipment

	USD'00 Oil and gas properties	USD'00 Exploration and evaluation assets	USD'000 Capital leases	USD'000 Total
Cost				
Balance at January 1, 2018	783,253	1,611	28,144	813,008
Additions	10,698	-	10,309	21,007
Change in ARO estimates	(25,325)	-	-	(25,325)
Write-off	(458)	-	(714)	(1,172)
Balance at December 31, 2018	**768,168**	**1,611**	**37,739**	**807,518**
Adjustment for change in accounting policies (Note 4.1)	-	-	(37,739)	(37,739)
Additions	10,513	1,265	-	11,778
Change in ARO estimates	1,055	-	-	1,055
Write-off	(201)	-	-	(201)
Balance at December 31, 2019	**779,535**	**2,876**	**-**	**782,411**
Additions	3,452	608	-	4,060
Change in ARO estimates	1,657	-	-	1,657
Disposal	(4)	-	-	(4)
Write-off	(222)	(287)	-	(509)
Transfer	1,256	(1,256)	-	-
Balance at December 31, 2020	**785,674**	**1,941**	**-**	**787,615**
Accumulated depletion/ Depreciation				
Balance at January 1, 2018	636,602	287	24,786	661,675
Charge for the year	21,676	-	1,832	23,508
Balance at December 31, 2018	**658,278**	**287**	**26,618**	**685,183**
Adjustment for change in accounting policies (Note 4.1)	-	-	(26,618)	(26,618)
Charge for the year	13,038	-	-	13,038
Balance at December 31, 2019	**671,316**	**287**	**-**	**671,603**
Charge for the year	17,835		-	17,835
Disposal	(4)		-	(4)
Write-off	-	(287)	-	(287)
Balance at December 31, 2020	**689,147**	**-**	**-**	**689,147**
Accumulated impairment				
Balance at January 1, 2018	5,638	-	-	5,638
Reversal of impairment	(1,214)	-	-	(1,214)
Balance at December 31, 2018	**4,424**	**-**	**-**	**4,424**
Reversal of impairment	(4,253)	-	-	(4,253)
Balance at December 31, 2019	**171**	**-**	**-**	**171**
Impairment	41,424	-	-	41,424
Balance at December 31, 2020	**41,595**	**-**	**-**	**41,595**
Net book value				
Balance at December 31, 2018	**105,466**	**1,324**	**11,121**	**117,911**
Balance at December 31, 2019	**108,048**	**2,589**	**-**	**110,637**
Balance at December 31, 2020	**54,932**	**1,941**	**-**	**56,873**

Property, plant and equipment as at December 31, 2020 included $6,338 thousand ($3,412 thousand in 2019, $10,684 thousand in 2018) of costs that are not subject to depreciation, depletion and amortization as a result of development projects pending production, acquisition costs for probable reserves and exploration costs.

The extension of production period for Production Sharing Contract ("PSC") Block PM3 was granted up to December 31, 2027 for crude oil and natural gas. Block PM3 consists of 89 oil and gas active wells with 99 strings and 24 water and gas active injector wells with 26 strings. Block PM3 is located at the east of Peninsular Malaysia.

The property, plant and equipment written off during the year mainly relate to previously impaired PM3 exploration due to no future development plans are expected. In prior years, the property, plant and equipment written off mainly relate to the write-off of development inventories in 2018 and 2019, and de-recognition of capital lease in 2018.

In 2020, in view of the situation in the commodity markets, the social and economic consequences of the COVID-19 pandemic, the Company carried out a review of the recoverable amount of the property, plant and equipment. The methodology used by the Company to estimate the recoverable amount of assets is, in general, the value in use is calculated by discounting to present value the future cash flows expected to be derived from the operation of these assets. The review led to a recognition of impairment loss on property, plant and equipment of $41,424 thousand ($4,253 thousand of reversal in 2019) which has been recognised in the statement of profit or loss and other comprehensive income. The key assumptions used in performing the impairment assessment are disclosed in Note 5.2.1 to the financial statements.

The reversal of impairment loss recognized in 2018 and 2019 was arising from the annual planed usage review for the drilling inventories performed by the Company which indicated that these inventories previously impaired can be utilised in the future period.

The Company has performed the following sensitivity analysis to assess impact from the changes in the key assumptions used to determine the recoverable amount and the impairment loss to be recorded in oil and gas properties and right-of-use assets during the financial year:

	Increase (+)/Decrease (-)	USD'000 Impairment losses	USD'000 Loss for the period
Change in oil and gas price	+10%	21,733	27,732
	-10%	73,031	79,030
Change in oil and gas production	+5%	34,570	40,569
	-5%	60,194	66,193
Change in discount rate	+1%	49,848	55,847
	-1%	44,816	50,817

The Company has taken out insurance policies to cover the risk of damage to its property, plant and equipment. The coverage of these policies is considered sufficient.

Fully depreciated property, plant and equipment amount $2,452 thousand at December 31, 2020 ($2,457 thousand in 2019, $2,532 thousand in 2018).

At December 31, 2020, 2019 and 2018, the Company has no commitments to purchase property, plant and equipment.

11. Right-of-use assets

This note provides information about ROU assets, expenses and cash flows related to leases.

Amount recognised in the statement of profit or loss and other comprehensive income as per below:

	USD'000 2020	USD'000 2019
Depreciation expense on ROU assets	2,480	2,821
Impairment losses on ROU assets (Note 22(e))	5,958	-
Interest expenses on leases (Note 17)	1,034	1,205
Expenses related to short-term leases (included in other operating expenses)	644	1,426

The total cash outflows for leases in 2020, including the payment made for short-term leases were $4,315 thousand ($5,135 thousand in 2019).

	USD'000 Buildings	USD'000 Vessels	USD'000 Computer software and equipment	USD'000 Total
Cost				
Balance at January 1, 2019	-	-	-	-
Adjustment for change in accounting policies (Note 4.1)	-	45,657	169	45,826
Additions	-	-	-	-
Balance at December 31, 2019	-	**45,657**	**169**	**45,826**
Additions	9	92	-	101
Change in estimates	-	-	(43)	(43)
Balance at December 31, 2020	**9**	**45,749**	**126**	**45,884**
Balance at January 1, 2019	-	-	-	-
Adjustment for change in accounting policies (Note 4.1)	-	26,618	-	26,618
Charge for the year	-	2,787	34	2,821
Balance at December 31, 2019	-	**29,405**	**34**	**29,439**
Charge for the year	1	2,456	23	2,480
Balance at December 31, 2020	**1**	**31,861**	**57**	**31,919**
Accumulated Impairment				
Balance at January 1, 2019/ December 31, 2019	-	-	-	-
Impairment	-	5,958	-	5,958
Balance at December 31, 2020	-	**5,958**	-	**5,958**
Net carrying value				
Balance at December 31, 2019	-	**16,252**	**135**	**16,387**
Balance at December 31, 2020	**8**	**7,930**	**69**	**8,007**

The impairment assessment carried out by the Company in 2020 as disclosed in Note 10 includes the review of the recoverable amount of the right-of-use assets. The review led to a recognition of impairment loss on right-of-use assets of $5,958 thousand which has been recognised in the statement of profit or loss and other comprehensive income. The sensitivity analysis to assess impact from the changes in the key assumptions used to determine the recoverable amount and the impairment loss to be recorded in right-of-use assets are disclosed in Note 10.

12. Joint Operation

In accordance with the terms by the joint operation, the Company has a participating interest of 12.70% in Peninsular Malaysia Offshore Block PM3-CAA at the end of the 2020 and 2019 financial periods. Repsol Oil and Gas Malaysia Limited ("RML") was appointed as the operator to manage the PSC under a Joint Operating Agreement ("JOA") for joint operations of the Block PM-3 CAA. Details of the JOA is disclosed in Note 1.

			USD'000	
	Working Interest	2020 Revenue	2019 Revenue	2018 Revenue
PM3	12.67%	43,938	65,592	68,450
Total		**43,938**	**65,592**	**68,450**

The Company accounts for its investments in joint operations recording in its statement of financial position the proportionate share of the jointly controlled assets and jointly incurred liabilities that corresponds based on its percentage of participation (working interest).

Likewise, the corresponding part of the income generated, and the expenses incurred by the joint operation are recognized in the statement of profit or loss and other comprehensive income.

13. Sinking fund

	USD'000 2020	USD'000 2019	USD'000 2018
Balance, beginning of year	15,917	12,742	8,007
Abandonment cess payment during the year	3,946	8,225	4,735
Revision in discount	1,669	(5,050)	-
Accretion expense	383	-	-
Foreign Exchange	51	-	-
Balance, end of year	**21,966**	**15,917**	**12,742**

The Company contributed to a separate fund established to fund future decommissioning obligations. The balance at December 31, 2020 amounts $21,966 thousand ($15,917 thousand in 2019, $12,742 thousand in 2018).

14. Trade and other receivables

	USD'000 2020	USD'000 2019	USD'000 2018
Accounts receivable	4,879	3,696	6,731
Accounts receivables from partners (underlift)	64	4,621	-
Less: Loss allowance during the year	(1)	(10)	(58)
Total	**4,942**	**8,307**	**6,673**

The Company is exposed to credit risk, which is the risk that customer or counterparty will fail to perform an obligation or settle a liability, resulting in financial loss to the Company. The maximum credit risk exposure associated with trade and other receivables is the carrying value. At December 31, 2020, the Company had trade receivable of $4,879 thousand ($3,696 thousand in 2019, $6,731 thousand in 2018), 31% of which is receivable from PETRONAS, the Malaysian national oil company, 69% of which is receivable from Petro Vietnam National Oil Company.

Crude oil production is sold to PETCO Trading Labuan Company, a wholly owned subsidiary of PETRONAS. Natural gas production is sold at the wellhead to PETRONAS. Accounts receivable have arisen primarily from these sales and are expected to be received in full.

Accounts receivables from partners refers to the oil product that the Company was entitled to, based on the production sharing contract, of which lifted by partners. At each reporting date, the amount is valued at the lower of current market value and fair value at the date of lifting.

15. Inventories

	USD'000 2020	USD'000 2019	USD'000 2018
Product inventory	7,356	7,415	7,204
Total	**7,356**	**7,415**	**7,204**

Product inventory mainly comprises of spare parts, equipment, steel line pipe, pressure vessels and other equipment that required maintaining in order to support the day-to-day production operation.

Inventories recognised as an expense during the year ended December 31, 2020 amounted to $1,673 thousand ($3,456 thousand in 2019, $4,445 thousand in 2018) and included as supplies in the statement of profit or loss and other comprehensive income.

The production inventories written off during the year amounted to $394 thousand ($1 thousand in 2019, $79 thousand in 2018) and these were recognised as an expense during the year ended December 31,2020.

As at December 31, 2020, the provisions made for the production inventories amounted to $318 thousand ($400 thousand in 2019, $484 thousand in 2018) as a result of the annual material review. These were included in other operating expense in the statement of profit or loss and other comprehensive income.

16. Loans from related parties

	USD'000 TEHS	USD'000 RTYGF	USD'000 RGDSL	USD'000 Total
Balance at January 1, 2018	49,758	-	-	49,758
Draws during the year	-	2,500	3,000	5,500
Repayments during the year	(6,039)	-	(9,517)	(15,556)
Interest during the year	313	167	1,203	1,683
Transfer of loan	(44,032)	(2,667)	46,699	-
Balance at December 31, 2018	-	-	41,385	41,385
Draws during the year	-	-	12,334	12,334
Repayments during the year	-	-	(38,200)	(38,200)
Interest during the year	-	-	1,118	1,118
Balance at December 31, 2019	-	-	16,637	16,637
Draws during the year	-	-	25,500	25,500
Repayments during the year	-	-	(24,726)	(24,726)
Interest during the year	-	-	805	805
Balance at December 31, 2020	-	-	18,216	18,216

On December 1, 2017, TE Holdings S.A.R.L. ("TEHS") loaned $65,180 thousand to the Company as part of the Malaysia Dividend payment for the year ended 2017. Interest is based on a LIBOR 1Y flat rate. The interest is set daily. Accrued interest is due on repayment of borrowings and any outstanding interest payable at month end if not paid in cash is added to the principal. The loan was transferred to Repsol Tesoreria Y Gestion Financiera,S.A. ("RTYGF") and subsequently to Repsol Gestion Divisa, S.L. ("RGDSL") during the year. The principal outstanding at December 31, 2018 was nil.

On February 19, 2018, RTYGF loaned $2,500 thousand to the Company. Interest is based on each interest period at LIBOR plus 1%. Accrued interest is due on repayment of borrowings. The principal outstanding at December 31, 2018 was nil as the loan had been transferred to RDGSL during the year. The loan matures on February 19, 2019.

On April 26, 2018, Repsol Gestion Divisa, S.L. ("RGDSL") lent $3,000 thousand to the Company. Interest is based on each interest period at LIBOR 12M plus 1.66% (LIBOR 12 M plus 1.6% in 2019). Accrued interest is due on repayment of borrowings. The principal outstanding at December 31, 2020 was $17,744 thousand plus accrued interest of $472 thousand. The loan matures on April 26, 2021.

17. Trade and other payables

	USD'000 2020	USD'000 2019	USD'000 2018
Long-term payable	-	-	9,948
Long-term lease obligation	14,276	16,962	11,654
Total non-current	14,276	16,962	21,602
Cash calls payable to RML	5,054	11,247	(235)
Trade payables and other	57	303	663
Accrued liabilities	91	97	490
Current lease obligation	2,661	2,537	2,066
Current signature bonus payable	-	10,314	-
Total current	7,863	24,498	2,984

17.1 Long-term payable

Long-term payable as of December 31, 2018 corresponds to the outstanding balance due to host governments related to the PSC Block PM3 Extension signature bonus. Total signature bonus amounted to $60,000 thousand, balance payable by the Company in February 2020 is therefore recognised as current payable as of December 31, 2019

17.2 Lease obligation

Lease obligation as of December 31, 2018 relates to the lease for the Northern Fields which commenced on March 25, 2009. The 10-year Primary Term shall expire on March 25, 2019. The lease was subsequently extended for an additional 10 years, with effect from January 1, 2018.

On adoption of MFRS 16/IFRS 16 effective from January 1, 2019, the lease is recognised as part of the lease obligation as of December 31, 2019 in the statement of financial position. The changes in accounting policies are reflected in Notes 3.19 and 4.1.

The Company leases various offices, vessels and computer software and equipment. Rental contracts are typically made for fixed period of 2 to 20 years.

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The lease agreements do not impose any covenants, but leased assets may not be used as security for borrowing purpose.

At December 31, 2020, $20,847 thousand ($23,834 thousand in 2019, $17,404 thousand in 2018) has been identified as the total undiscounted liability of the Company. This is discounted at a rate ranging from 7.51% to 9.38% (2019 - 4.56% to 9.65%, 2018 - 5.69%). Total lease payments incurred in 2020 was $3,671 thousand ($3,709 thousand in 2019, $1,918 thousand in 2018). Interest expense on the long-term lease obligation incurred in 2020 was $1,034 thousand ($1,205 thousand in 2019, $815 thousand in 2018).

	USD'000 2020	USD'000 2019	USD'000 2018
Minimum lease payments			
Less than one year	2,661	2,537	2,066
One to five years	12,423	12,439	8,444
More than five years	5,403	8,858	6,894
Total future minimum lease payments	**20,487**	**23,834**	**17,404**
Less: future finance charges	(3,550)	(4,335)	(3,684)
Present value of lease obligation	**16,937**	**19,499**	**13,720**
Present value of lease obligation			
Less than one year	2,661	2,537	2,066
One to five years	9,433	2,673	5,379
More than five years	4,843	14,289	6,275
Total	**16,937**	**19,499**	**13,720**

There are no contingent rentals paid during the year (nil in 2019 and 2018).

17.3 Other current liabilities

Trade payables and others are unsecured and are usually paid within 30 days of recognition.

Cash call payable refers to net share of working capitals and accruals on Production Sharing Contract.

Current lease obligation as of December 31, 2018 relates to amount payable for leasing of PM3 Northern Field Ocean Going Vessel ("PM-3") contract.

On adoption of MFRS 16/IFRS 16 effective from January 1, 2019, the current obligations relate to the leasing of various offices, vessels and computer software and equipment as described in Note 17.2.

Carrying amount of current liabilities does not significantly defer from its fair value.

18. Provisions and contingencies

18.1 Asset retirement obligation ("ARO")

ARO movement during 2020, 2019 and 2018 is as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Asset retirement obligation, beginning of year	41,910	39,021	65,958
Accretion	1,337	1,834	2,658
Liabilities incurred and revision in estimates	1,657	1,055	(29,595)
Asset retirement obligation, end of year	**44,904**	**41,910**	**39,021**

The estimated undiscounted asset retirement obligation at December 31, 2020 was $52,894 thousand ($53,676 thousand in 2019, $58,193 thousand in 2018) and is expected to be incurred in phases, starting from year 2022. The expiry of the Company's Production Sharing Contract (PM-3 CAA) subsequent to extension is in 2027.

The ARO has been discounted using a discount rate of 2.36% (2019: 3.19%, 2018: 4.70%).

Total accretion for the year ended December 31, 2020 of $1,337 thousand ($1,834 thousand in 2019, $2,658 thousand in 2018) has been included in finance expenses (see Note 22(f)).

19. Commitments

Major commitments for the Company in 2020 include costs associated with the PM-3 CAA extension, PM-3 Southern Field and PM-3 Northern Field Support Vessels.

19.1 Non-cancellable operating lease commitments

On adoption of MFRS 16/IFRS 16 effective on January 1, 2019, leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company. Therefore, no operating lease commitment disclosure is required for 2019 and 2020.

	USD'000 2018
Future minimum rental payable:	
Within one year	1,857
Later than one year and not more than five years	6,378
Later than five years	1,508
Total	**9,743**

19.2 Capital commitments in respect of investment in petroleum operations in Malaysia

Capital expenditures not provided for in the financial statements are estimated to be as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Authorised and contracted for	22,189	4,226	7,185

20. Share Capital

The Company's authorized share capital consists of an unlimited number of common shares without nominal or par value. The number of shares issued and outstanding were 1,001 as at December 31, 2020 (1,001 in 2019 and 2018), in the amount of $11,668 thousand ($11,668 thousand in 2019 and 2018).

At December 31, 2020, 2019 and 2018, Fortuna International Petroleum Corporation owns 100% of the Company's share capital.

The shares of the Company are not listed on any Stock Exchange.

21. Income taxes

	USD'000 2020	USD'000 2019	USD'000 2018
Tax (expense)/income attributable to profit is made up of:			
CURRENT CORPORATE INCOME TAX			
Current year	(3,829)	(651)	(441)
Over/(under) provision in prior year	1,896	(177)	-
Previous years corporation tax provision	(15,785)	(5,111)	-
Total	**(17,718)**	**(5,939)**	**(441)**
DEFERRED CORPORATE INCOME TAX			
Recognition of temporary differences	23,648	(9,144)	(10,519)
Total	**23,648**	**(9,144)**	**(10,519)**
Total income tax recovery/(expense)	**5,930**	**(15,083)**	**(10,960)**

The Company accounts for income taxes using the taxes liability method. As a result, the Company's income tax expense varies from the amount that would otherwise result from the application of the statutory income tax rates as set out below:

	USD'000 2020	USD'000 2019	USD'000 2018
(Loss)/Profit before income tax	(59,091)	19,455	21,837
Expected income tax expense at Barbados corporate tax rate (2020 - 2.5%, 2019 – 1.5%, 2018 – 1.5%)	1,477	(292)	(328)
Non-deductible expenses	(3,446)	(4,464)	(3,169)
Income not subject to tax	31	20	155
Foreign tax rate differential	21,767	(5,059)	(7,997)
Previous years corporation tax provision	(15,785)	(5,111)	-
Over/(under) provision in prior year	1,896	(177)	-
Change in Barbados tax rate (1.5% to 2.5%)	(383)	-	-
Deferred tax true-up	373	-	379
Income tax recovery/(expense)	**5,930**	**(15,083)**	**(10,960)**

Previous years tax provision expense in amount of $15,785 thousand ($5,111 thousand in 2019) correspond to the additional tax and penalty for Block PM3 for the year of assessment 2014 to 2016, as well as to corporate income tax for the year of assessment 2015 to 2017 and potential tax and penalties on the YAs open for review by the Inland Revenue Board of Malaysia ("IRB").

Deferred Tax expense is attributable to the recognition of temporary differences under Barbados tax legislation and Malaysia Income tax regulation (Petroleum Income Tax regulation, under which Malaysian Petroleum Sharing Contracts are taxed), and correspond mainly to the difference between tax and accounting depreciation and amortization, abandonment provision and sinking fund.

The movement of the deferred tax assets/(liabilities) of the Company are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Balance at January 1	(24,063)	(14,593)	(4,375)
Credit/(Charge) to profit or loss			
Property, plant and equipment	21,208	3	33,674
Right-of use assets	3,081	(6,473)	-
Sinking fund	(2,609)	(1,207)	(656)
Underlift of crude oil	1,309	(1,327)	(1)
Leases	(974)	2,196	(51)
Asset retirement obligation	1,631	1,727	(38,147)
Overlift of crude oil	-	75	(2,511)
Unutilised tax losses	-	(4,427)	(3,525)
Adjustment on adoption of MFRS 9/IFRS 9	-	-	3
Others	4	(34)	996
Exchange differences	62	(3)	-
Balance at December 31	**(351)**	**(24,063)**	**(14,593)**

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax relate to the same tax authority. The following amounts, determined after appropriate offsetting, are shown in the statement of financial position:

	USD'000 2020	USD'000 2019	USD'000 2018
Deferred tax assets	24,655	23,965	24,473
Deferred tax liabilities	(25,006)	(48,028)	(39,066)
Balance at December 31	**(351)**	**(24,063)**	**(14,593)**

The amount of the deferred tax assets are composed by the temporary differences generated by the asset retirement obligation and capital leases, and the amount of deferred tax liabilities are composed by temporary differences between tax and accounting depreciation and amortization and by the temporary differences generated by the sinking fund.

The components and movements of deferred tax liabilities and assets during the financial year prior to offsetting are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
DEFERRED TAX ASSETS			
Lease obligation	6,436	7,410	5,214
Asset retirement obligation	18,186	16,555	14,828
Unutilised tax losses	-	-	4,427
Others	33	-	4
Total	**24,655**	**23,965**	**24,473**
DEFERRED TAX LIABILITIES			
Property, plant and equipment	(12,700)	(33,908)	(33,911)
Right-of-use assets	(3,392)	(6,473)	-
Sinking fund	(8,896)	(6,287)	(5,080)
Underlift of crude oil	(18)	(1,327)	-
Overlift of crude oil			(75)
Others	-	(33)	-
Total	**(25,006)**	**(48,028)**	**(39,066)**

During 2019, the Company performed a reassessment of the tax position of the Company in Barbados and adjusted the temporary differences to adjust and reflect tax assets and liabilities as per the Company's activities.

The domestic income tax is calculated according to PITA statutory rate of 38% (2019 and 2018: 38%) of the estimated assessable profit from Petroleum Operations in Malaysia.

The Company was previously licensed under the International Business Companies Act Cap. 77 which has been repealed. The Company continues its licensing under the Companies Act Cap. 308. which allows provision for the same previous benefits via grandfathering under the International Business Companies (Repealed) Act, 2018-40, until the Company transitions to the new regime in 2021. The Company qualified for grandfathering. As a result the tax rates remain at 1.0% to 2.5%.

On the repeal of the International Business Companies Act, Cap. 77., the Income Tax Act Cap. 73 was amended to apply new staggered tax rates from 1.0% to 5.5% based on the Company's income. The revised tax rates effective January 1, 2020 are as follows: taxable income up to $500 Thousand is subject to tax at 5.5%, taxable income exceeding $500 Thousand up to the next $10,000 Thousand at 3.0%, taxable income exceeding $10,000 Thousand up to $15,000 Thousand at 2.5% and all amounts in excess of $15,000 Thousand at 1.0%.

Income tax receivable in amount of $1,980 thousand correspond to the amount of petroleum income taxes overpaid to Malaysian Inland Revenue Board and Barbados Revenue Authority, and expected to be received within one year.

Long Term tax receivable in amount of $5,044 thousand ($3,353 thousand in 2019, $3,286 thousand in 2018) correspond to the amount of petroleum income taxes overpaid to Vietnamese Tax Authority in prior years, and expected to be received within more than one year.

Income tax payable in amount of $18,166 thousand ($7,387 thousand in 2019) correspond to the additional tax and penalty for Block PM3 for the year of assessment 2014 to 2016. Income tax payable in amount of $17,020 thousand is related to corporate income tax for the year of assessment 2015 to 2017 while the remaining payable of $3,442 thousand ($401 thousand in 2019, $900 thousand in 2018) is related to the current income tax provision.

22. Revenue and expenses

(a) Revenue

Operating revenue is broken-down as follows:

	USD'000 Crude oil	USD'000 Gas	USD'000 Total
2018			
Thailand	16,326	-	16,326
China	4,155	-	4,155
Malaysia	4,970	9,678	14,648
Vietnam	-	33,321	33,321
Total sales	25,451	42,999	68,450
2019			
Thailand	29,603	-	29,603
China	1,755	-	1,755
Malaysia	3,679	9,984	13,663
Vietnam	-	20,571	20,571
Total sales	35,037	30,555	65,592
2020			
Thailand	14,596	-	14,596
China	8,198	-	8,198
Australia	1,595	-	1,595
Malaysia	-	9,859	9,859
Vietnam	-	9,690	9,690
Total sales	24,389	19,549	43,938

The Company derives its revenue from contracts with customers from the above geographical markets for the sales of crude oil and gas.

(b) Depletion, depreciation and amortization

	USD'000 2020	USD'000 2019	USD'000 2018
Depletion, depreciation and amortization of oil and gas properties (note 10)	17,835	13,038	21,676
Depreciation of capital lease assets (note 10)	-	-	1,832
Amortization of intangible assets (note 9)	133	79	13
	17,968	13,117	23,521
Depreciation and amortization of right-of-use assets (Note 11)	2,480	2,821	-
Total	20,448	15,938	23,521

(c) Other operating expenses

Other operating expenses are broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Rental	644	1,426	684
Inventory written off	394	1	79
Repair and maintenance expenses	4,872	7,982	10,197
Write-down of inventories	318	-	484
Oil and gas properties written off (note 10)	222	201	458
De-recognition of capital lease assets (note 10)	-	-	714
(Write-back)/Loss allowance on accounts receivable	(9)	(46)	51
Rebilling of personnel expenses	4,456	5,252	6,198
Other taxes	733	1,317	1,742
Write-off of receivables from partner	-	1,015	-
Professional services	1,052	1,073	188
Freight charges	1,320	1,578	2,649
Tax penalties (Note 21)	11,937	2,275	-
Other expenses	2,387	4,809	2,502
Total	**28,326**	**26,883**	**25,946**

(d) Other operating income

	USD'000 2020	USD'000 2019	USD'000 2018
Other miscellaneous income	326	442	427
Other exceptional income	-	-	4,270
Reversal of write-down of inventories	-	85	-
Total other operating income	**326**	**527**	**4,697**

Other miscellaneous income mainly relates to processing fee income and port charges recovery.

Other exceptional income is related to recognition of the revision in the estimate of ARO into the income statement because the decrease in ARO has exceeded the carrying amount of the related assets recorded in oil and gas properties.

(e) Net impairment losses

	USD'000 2020	USD'000 2019	USD'000 2018
Impairment losses/(reversal) on property, plant and equipment	41,424	(4,253)	(1,214)
Impairment losses on right-of-use assets	5,958	-	-
Total	**47,382**	**(4,253)**	**(1,214)**

The impairment losses and its reversal relates to the amount recognised during the year as a result of the annual impairment assessment. Detailed information on impairment losses are disclosed in Notes 5.2.1, 10 and 11.

(f) Financial result

Financial result is broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Interest income on miscellaneous	81	72	84
Total finance income	**81**	**72**	**84**
Interest expense on lease (Note 17)	(1,034)	(1,205)	(815)
Interest expense on others	(16)	(379)	(692)
Interest expense on loans from related parties (Note 16)	(805)	(1,118)	(1,683)
	(1,855)	**(2,702)**	**(3,190)**
Accretion expense for ARO (Note 18)	(1,337)	(1,834)	(2,658)
Accretion expense for sinking fund (Note 13)	2,052	(5,050)	-
Total finance expenses	**(1,140)**	**(9,586)**	**(5,848)**

Accretion expense for ARO is the unwinding of the interest of discounted long-term ARO liabilities.

Accretion expense for sinking fund consists of revision in discount rate (2020: 0.74% to 2.59%, 2019: 3.3%) and the accretion expense of the sinking fund.

	USD'000 2020	USD'000 2019	USD'000 2018
Net unrealised gain on foreign exchange	9	253	366
Net realised gain on foreign exchange	80	1	(632)
Total foreign exchange gain/(loss)	**89**	**254**	**(266)**

23. Related parties

23.1 Related parties' balances and transactions

Balances with related parties as at December 31, 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Amount due from related company:			
Repsol Oil & Gas Malaysia Limited	-	-	27
Due from related party	**-**	**-**	**27**
Amount due to:			
Intermediate holding company			
Repsol Exploracion, S.A.	-	8	-
Related company			
Repsol Tesoreria y Gestion Financiera	5	4	-
Due to related parties	**5**	**12**	**-**
Loan from related company:			
Repsol Gestion Divisa, S.L.	18,216	16,637	41,385
Loan from related party	**18,216**	**16,637**	**41,385**

In the normal course of business, the Company undertakes, a variety of transactions with certain related companies, each of whom share a common ultimate holding company (Repsol, S.A.).

The amounts due to/from related parties which mainly arose from non-trade transactions are unsecured, non-interest bearing and are repayable on demand.

Loans from related parties is detailed in Note 16.

The material related party transactions for 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Loans from related parties:			
- Repsol Gestion Divisa, S.L.			
At January 1	16,637	41,385	-
Loans advanced	25,500	12,334	3,000
Loans repayment made	(24,727)	(38,200)	(9,517)
Interest charged	805	1,118	1,203
Loans transferred	-	-	46,699
At December 31	**18,215**	**16,637**	**41,385**
- TE Holdings S.A.R.L.			
At January 1	-	-	49,758
Loans repayment made	-	-	(6,039)
Interest charged	-	-	313
Loans transferred	-	-	(44,032)
At December 31	**-**	**-**	**-**
- Repsol Tesorería Y Gestión Financiera, S.A.			
At January 1	-	-	
Loans advanced	-	-	2,500
Interest charged	-	-	167
Loans transferred	-	-	(2,667)
At December 31	**-**	**-**	**-**

23.2 Information referring to the Directors

Remuneration and other benefits paid to the Directors

In 2020, the Company has paid $10.8 thousand to its Directors for attending to the functions inherent to the Company's management ($12.2 thousand in 2019 and 2018).

At December 31, 2020, 2019 and 2018, the Company had not assumed any obligations regarding pensions or life insurance for its Directors, nor were any advances, loans or credits made to them by the Company.

24. Production sharing contract

The Company secures the rights to carry out exploration activities in the international blocks through a Production Sharing Contract ("PSC") arrangement with respective national oil company.

Under the terms of the PSC that the Company has entered into, the PSC contractor bears all costs. The PSC contractor funds the work outlined in the approved Work Programme and Budget ("WP&B") and upon production, may recover the costs in barrels of crude oil or gas equivalent (referred to as "cost oil" or "cost gas"), in accordance with the terms of the PSC. Costs remaining unrecovered can be carried forward for recovery against production of crude oil or gas equivalent in subsequent quarter. The contractor's share of production also includes an element of profit (referred to as "profit oil" or "profit gas").

Title to all equipment and other assets purchased or acquired by the PSC contractor exclusively for the purpose of petroleum operations, and which costs are recoverable in barrels of cost oil or gas equivalent are vested with the national oil company. The contractors retain the right of use of those assets for the duration of the PSCs and the corresponding value of the right of these assets is minimised in the financial statements of the Company as intangible assets and plant and equipment.

The Company recognises the cost of dismantling and removing the assets and restoring the site on which they are located when there is an obligation to do so.

25. Events subsequent to year end

Since the end of 2020, there have been no significant events that could affect the financial statements for 2020 or the normal course of the Company's business.

Effective June 30, 2021 the benefits under the International Business Companies Act (Repealed) Act 2018-40 will expire. The company will be required to comply with the Companies (Economic Substance) Act, 2019-43 (CESA) with effect from January 1, 2021. The Act imposes an economic substance test on Barbados-resident companies that are managed and controlled in Barbados or incorporated/registered in Barbados and not considered a tax resident in another jurisdiction. The Act also requires that the companies conduct relevant activities as defined under the Act. The Company is in compliance with the new Act based on the management's assessment.

26. Other information

26.1 Contingent liabilities

At December 31, 2020, 2019 and 2018 the Company had not assumed any tax or legal contingent liabilities.

27. Reconciliation of liabilities arising from financing activities

The table below details the reconciliation of the opening and closing amounts for the liabilities for which cash flows have been, or would be classified as financing activities in the statement of cash flows:

Loans from related parties

	USD'000 2020	USD'000 2019	USD'000 2018
At January 1	16,637	41,385	49,758
Cash flows from:			
- Principal:			
Drawdown	25,500	12,334	5,500
Repayment	(24,726)	(38,200)	(15,556)
Interest charged	805	1,118	1,683
At December 31	**18,216**	**16,637**	**41,385**

Lease obligations

	USD'000 2020	USD'000 2019	USD'000 2018
At January 1	19,499	13,720	4,515
Implementation of MFRS 16/IFRS 16 (Note 4.1)	-	8,283	-
Cash flows from lease payment	(3,671)	(3,709)	(1,918)
New lease	58	-	10,308
Foreign exchange	17	-	-
Interest charged	1,034	1,205	815
At December 31	**16,937**	**19,499**	**13,720**

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The Board of Directors
Hibiscus Petroleum Berhad
2nd floor,
Syed Kechik Foundation Building,
Jalan Kapas, Bangsar,
59100 Kuala Lumpur.

4 October 2021

PwC/TEH/NNH/sw/0897B1

Dear Sirs,

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Talisman Vietnam Limited

Our Opinion

We have audited the accompanying financial statements of Talisman Vietnam Limited ("TVL" or the "Target Company") which comprise the statements of financial position as at 31 December 2018, 31 December 2019 and 31 December 2020, the statements of profit or loss and other comprehensive income, statements of changes in shareholder's equity and statements of cash flows for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, and a summary of significant accounting policies and other explanatory notes (together, the "Financial Statements"), as set out on pages 1 to 32. The Financial Statements have been prepared for purposes of inclusion in Hibiscus Petroleum Berhad ("HPB")'s circular to shareholders of HPB (the "Circular to Shareholders") in connection with the proposed acquisition of Fortuna International Petroleum Corporation and its subsidiaries by HPB (the "Proposal").

In our opinion, the Financial Statements give a true and fair view of the financial position of the Target Company as at 31 December 2018, 31 December 2019 and 31 December 2020 and of its financial performance and cash flows for each of the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020, in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS").

PricewaterhouseCoopers PLT (LLP0014401-LCA & AF 1146), Chartered Accountants, Level 10, 1 Sentral, Jalan Rakyat, Kuala Lumpur Sentral, P.O. Box 10192, 50706 Kuala Lumpur, Malaysia
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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0897B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Talisman Vietnam Limited (Continued)

Basis for Opinion

We conducted our audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing. Our responsibilities under those standards are further described in the Reporting Accountant's Responsibilities for the Audit of the Financial Statements section of our report. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence and Other Ethical Responsibilities
We are independent of the Target Company in accordance with the By-Laws (on Professional Ethics, Conduct and Practice) of the Malaysian Institute of Accountants ("By-Laws") and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards) ("IESBA Code"), and we have fulfilled our other ethical responsibilities in accordance with the By-Laws and the IESBA Code.

Directors' Responsibilities for the Financial Statements

The Directors of the Target Company are responsible for the preparation of the Financial Statements for the financial years ended 31 December 2018, 31 December 2019 and 31 December 2020 that gives a true and fair view in accordance with the MFRS and IFRS. The Directors of the Target Company are also responsible for such internal control as the Directors of the Target Company determine is necessary to enable the preparation of the Financial Statements that is free from material misstatement, whether due to fraud or error.

In preparing the Financial Statements of the Target Company, the Directors of the Target Company are responsible for assessing the Target Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors of the Target Company either intend to liquidate the Target Company or to cease operations, or have no realistic alternative but to do so.

Reporting Accountant's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the Financial Statements of the Target Company as a whole are free from material misstatement, whether due to fraud or error, and to issue a report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with approved standards on auditing in Malaysia and International Standards on Auditing will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these Financial Statements.

The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0897B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Talisman Vietnam Limited (Continued)

Reporting Accountant's Responsibilities for the Audit of the Financial Statements (Continued)

As part of an audit in accordance with approved standards on auditing in Malaysia and International Standards on Auditing, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the Financial Statements of the Target Company, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Target Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the Directors of the Target Company.
- Conclude on the appropriateness of the Directors of the Target Company's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Target Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our report to the related disclosures in the Financial Statements of the Target Company or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our report. However, future events or conditions may cause the Target Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the Financial Statements of the Target Company, including the disclosures, and whether the Financial Statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Directors of the Target Company regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

pwc

The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/NNH/sw/0897B1
4 October 2021

Reporting Accountant's Opinion on the Financial Statements contained in the Accountant's Report of Talisman Vietnam Limited (Continued)

Restriction on Distribution and Use

This report is issued for the sole purpose of inclusion in the Circular to Shareholders of HPB in connection with the Proposal, and should not be relied on for any other purposes. Accordingly, we will not accept any liability or responsibility to any other party to whom our report is shown or into whose hands it may come.

Yours faithfully,

PRICEWATERHOUSECOOPERS PLT
LLP0014401-LCA & AF 1146
Chartered Accountant

TALISMAN VIETNAM LIMITED

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

Talisman Vietnam Limited

FINANCIAL STATEMENTS
FOR THE FINANCIAL YEARS ENDED 31.12.2020, 31.12.2019 AND 31.12.2018

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Talisman Vietnam Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Talisman Vietnam Limited

STATEMENTS OF FINANCIAL POSITION

(U.S. dollars)	Note	USD'000 As at 31.12.2020	USD'000 As at 31.12.2019	USD'000 As at 31.12.2018
Assets				
Intangible assets	8	-	1	2
Property, plant and equipment	9	5,927	6,879	4,905
Non-current Assets		**5,927**	**6,880**	**4,907**
Trade and other receivable	11	8,758	5,981	762
Due from related parties	18	-	-	1,939
Income tax receivable		262	-	-
Loan to related party	12	2,511	14,403	15,133
Cash and cash equivalents		949	1,000	1,372
Current Assets		**12,480**	**21,384**	**19,206**
Total Assets		**18,407**	**28,264**	**24,113**
Shareholder's equity and Liabilities				
Share capital	15	12	12	12
Reserves		3,445	3,445	3,445
Retained earnings		5,582	16,026	14,822
Shareholder's equity		**9,039**	**19,483**	**18,279**
Asset retirement obligation	14	2,246	2,423	652
Deferred tax liability	16	4,565	2,785	2,332
Non-current Liabilities		**6,811**	**5,208**	**2,984**
Due to related parties	18	2,152	3,066	1,531
Trade and other payables	13	405	384	1,196
Income taxes payable		-	123	123
Current Liabilities		**2,557**	**3,573**	**2,850**
Total Shareholder's equity and Liabilities		**18,407**	**28,264**	**24,113**

Notes 1 to 21 are an integral part of the financial statements.

Approved by Khoo Pooi Yin on behalf of the Directors on October 4, 2021:

ACCOUNTANT'S REPORT ON TVL (CONT'D)

Talisman Vietnam Limited

STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME
FOR THE FINANCIAL YEARS ENDED

(U.S. dollars)	Note	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Sales	17a	-	5,334	15,224
Revenue		-	5,334	15,224
Change in underlift	17b	3,781	1,078	(1,903)
Supplies		(3)	9	(13)
Other operating expenses	17c	(1,758)	(2,298)	(2,630)
Write-off of intercompany receivables	18	-	(1,913)	-
Depletion, depreciation and amortization	17d	(1,075)	(852)	(316)
Other operating income	17e	-	-	470
Results from operating activities		945	1,358	10,832
Interest	17f	31	243	172
Foreign exchange	17f	9	(6)	(1)
Net Finance income		40	237	171
Profit/(Loss) before income tax		985	1,595	11,003
Income tax expense	16	(1,429)	(391)	(4,608)
(Loss)/Profit for the year / Total comprehensive (expense)/income for the year		(444)	1,204	6,395

Notes 1 to 21 are an integral part of the financial statements.

Talisman Vietnam Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Talisman Vietnam Limited

STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
FOR THE FINANCIAL YEARS ENDED

	Share Capital	Reserves	Retained Earnings	Total
At 01.01.2018	**12**	**3,445**	**8,427**	**11,884**
Profit for the year / Total comprehensive income	-	-	6,395	6,395
At 31.12.2018/01.01.2019	**12**	**3,445**	**14,822**	**18,279**
Profit for the year / Total comprehensive income for the year	-	-	1,204	1,204
At 31.12.2019/01.01.2020	**12**	**3,445**	**16,026**	**19,483**
Dividends paid	-	-	(10,000)	(10,000)
Loss for the year / Total comprehensive expense for the year	-	-	(444)	(444)
At 31.12.2020	**12**	**3,445**	**5,582**	**9,039**

Notes 1 to 21 are an integral part of the financial statements.

Talisman Vietnam Limited
Financial statements for the years ended 31.12.2020, 31.12.2019 and 31.12.2018

Talisman Vietnam Limited

STATEMENTS OF CASH FLOWS
FOR THE FINANCIAL YEARS ENDED

(U.S. dollars)	USD'000 31.12.2020	USD'000 31.12.2019	USD'000 31.12.2018
Cash flows from Operating Activities			
Profit/(loss) for the period before tax	985	1,595	11,003
Adjustments to income:			
Depletion, depreciation and amortization	1,075	852	316
Interest income	(108)	(270)	(213)
Change in estimate for asset retirement obligations ("ARO")	-	-	(470)
Changes in working capital:			
Trade and other receivables	(2,777)	(5,315)	(1,856)
Trade and other payables	98	(780)	1,255
Related parties	(914)	3,473	3,859
Tax paid	(34)	158	(70)
Cash flows from/(used in) Operating Activities	**(1,675)**	**(287)**	**13,824**
Cash flows from Investing Activities			
Repayment from related party	2,000	6,000	4,724
Loan to related party	-	(5,000)	(14,430)
Capital expenditures	(376)	(1,085)	(2,767)
Cash flows from/(used in) Investing Activities	**1,624**	**(85)**	**(12,473)**
Net decrease in cash and cash equivalents	**(51)**	**(372)**	**1,351**
Cash and cash equivalents, beginning of year	**1,000**	**1,372**	**21**
Cash and cash equivalents, end of year	**949**	**1,000**	**1,372**

Non-cash activity – loan to related party and dividends paid (note 12).

Cash and cash equivalents only comprise of cash at banks.

Notes 1 to 21 are an integral part of the financial statements.

Talisman Vietnam Limited

Notes to the financial statements
For the years ended 31.12.2020, 31.12.2019, 31.12.2018

1. GENERAL INFORMATION

This Accountants' Report contains the financial statements of Talisman Vietnam Limited (hereinafter, "the Company") which comprise the statements of financial position as at December 31, 2020, December 31, 2019 and December 31, 2018, the statements of profit or loss and other comprehensive income, statements of changes in Shareholder's equity and statements of cash flows for the financial years ended December 31, 2020, December 31, 2019 and December 31, 2018, and a summary of significant accounting policies and other explanatory notes. The financial statements were prepared by management and approved by the Directors of the Company.

The Company was incorporated on February 20, 1992 under the Companies Act (Bermuda) as Lundin Vietnam Limited. On November 28, 2001 the Company was continued under the Barbados Companies Act Cap 308 (the "Act") and changed its name to Talisman Vietnam Limited. The Company was licensed and operated under the International Business Companies Act.

Effective January 1, 2019, the International Business Companies Act Cap. 77 was repealed, and all companies licensed under this act prior to its repeal, are now licensed under the Companies Act Cap. 308. Existing licensees will have until 2021 to transition into the regime and will have the benefit of grandfathering provisions until they do so under the International Business Companies (Repealed) Act 2018-40. In conjunction with the repeal of the International Business Companies Act Cap. 77, the Income Tax Act Cap. 73 was also amended. The amended Income Tax Act Cap. 73 applies new effective and staggered rates of tax from 1.0% - 5.5% based on a Company's net income. The Company elected to be grandfathered in accordance with International Business Companies (Repeal) Act, 2018-40 of Barbados until June 30, 2021. As a result the tax rates remain at 1.0% to 2.5%.

The Company is a wholly owned subsidiary of Fortuna International Petroleum Corporation. Its intermediate parent is Repsol Exploración S.A. and ultimate parent is Repsol S.A.

The Company is in the business of exploration, development, production and marketing of crude oil, natural gas and natural gas liquids in Malaysia and Vietnam.

The Company holds 70% participating interest in Block 46 Cai Nuoc (B46-CN). The extension to the B46-CN Production Sharing Contract ("PSC") was granted on September 12, 2017 whereby both the crude oil and natural gas productions were each extended from February 16, 2017 and August 13, 2019 respectively to December 31, 2027.

The registered office of the Company is 1st Floor, Limegrove Centre, Holetown, St. James, Barbados.

The address of the place of business of the Company is Level 33, Menara Citibank, 165, Jalan Ampang, 50450 Kuala Lumpur.

The Company is part of a group of companies under the terms of article 42 of the Code of Commerce, Repsol Group ("the Group"), whose ultimate parent company is Repsol, S.A. Repsol, S.A. is registered at the Madrid Companies Register in sheet no. M-65289. Its registered office is in Madrid, 44 Méndez Álvaro Street.

The items included in the financial statements of the Company are measured using the currency of the primary economic environment in which the entity operates ("the functional currency"). The functional currency of the Company is United States Dollar ("USD").

The Company does not have any personnel. Hence, no staff costs were incurred during the year.

2. BASIS OF PREPARATION OF THE FINANCIAL STATEMENTS

The financial statements of the Company for the year ended December 31, 2020, December 31, 2019 and December 31, 2018 have been prepared in accordance with the Malaysian Financial Reporting Standards ("MFRS") and International Financial Reporting Standards ("IFRS") and which include the Statement of financial position, Statement of Profit and Loss and Other Comprehensive income, Statement of Changes in Shareholder's equity, Statement of Cash Flows and Notes.

The preparation of financial statements in conformity with MFRS/IFRS requires the use of certain critical accounting estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reported period. It also requires the Directors to exercise their judgment in the process of applying the Company's accounting policies. Although these estimates and judgment are based on the directors' best knowledge of current events and actions, actual results may differ. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the financial statements are disclosed in Note 4 to the financial statements.

The financial statements reflect only the Company's interest in entitlement under the Production Sharing Contract ("PSC") and share of cost and assets and liabilities under the Joint Operating Agreements.

2.1 Amendments to published standards that are effective

Effective for annual period beginning on/after January 1, 2018

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2018:

- MFRS 9/IFRS 9 'Financial Instruments'
- MFRS 15/IFRS 15 'Revenue from Contracts with Customers'
- IFRIC 22 'Foreign Currency Transactions and Advance Consideration'

The Company has adopted MFRS 9/IFRS 9 and MFRS 15/IFRS 15 for the first time in the 2018 financial year, which resulted in changes in accounting policies. The Company accounting policies on financial instruments and revenue stream are disclosed in detail in Notes 3.7, 3.8 and 3.14 respectively. The impact from the adoption of these standards is not material to the Company.

Effective for annual period beginning on/after January 1, 2019

The Company has applied the following standards and amendments to the standards for the first time for the financial year beginning on January 1, 2019:

- MFRS 16/IFRS 16 'Leases'
- Amendments to MFRS 9/IFRS 9 'Prepayment Features with Negative Compensation'
- Amendments to MFRS 119/IAS 19 'Plan Amendment, Curtailment or Settlement'
- IFRIC 23 'Uncertainty over Income Tax Treatments'
- Annual Improvements to MFRSs/IFRSs 2015 - 2017 Cycle

The adoption of amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

Effective for annual period beginning on/after January 1, 2020

The Company has applied the following amendments to the standards for the first time for the financial year beginning on January 1, 2020:

- The Conceptual Framework for Financial Reporting (Revised 2018)
- Amendments to MFRS 101/IAS 1 and MFRS/IAS 8 108 'Definition of Material'
- Amendments to MFRS 9/IFRS 9, MFRS 139/IAS 39 and MFRS 7/IFRS 7 'Interest Rate Benchmark Reform'

The adoption of the amendments listed above did not have any impact on the current period or any prior period and is not likely to affect future periods.

2.2 Amendments to published standards that have been issued but not yet effective

Effective for annual period beginning on/after June 1, 2020

- In May 2020, the IASB issued COVID-19-Related Rent Concessions (Amendment to MFRS 16/IFRS 16) that grant an optional exemption for lessees to account for rent concessions occurring as a direct consequence of COVID-19.

  Such concessions might take a variety of forms, including payment holidays and deferral of lease payments. In many cases, this will result in accounting for the concession as a variable lease payment in the period(s) in which the event or condition that triggers the reduced payment occurs.

  The optional exemption permits a lessee to elect not to assess whether a COVID-19-related rent concession is a lease modification. A lessee that makes this election shall account for any change in lease payments resulting from the COVID-19-related rent concession the same way it would account for the change applying MFRS 16/IFRS 16 if the change were not a lease modification.

  The practical expedient applies only to rent concessions occurring as a direct consequence of COVID-19 and only if all of the following conditions are met:
  - The change in lease payments results in revised consideration for the lease that is substantially the same as, or less than, the consideration for the lease immediately preceding the change;
  - Any reduction in lease payments affects only payments originally due on or before June 30, 2021 (a rent concession meets this condition if it results in reduced lease payments on or before June 30, 2021 and increased lease payments that extend beyond June 30, 2021); and
  - There is no substantive change to other terms and conditions of the lease.

  The amendments shall be applied retrospectively.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

Effective for annual period beginning on/after January 1, 2022

- The amendments to MFRS 116/IAS 16 'Property, Plant and Equipment - Proceeds before Intended Use' prohibit an entity deducting from the cost of an item of property, plant and equipment the proceeds received from selling items produced by the property, plant and equipment before that asset is ready for its intended use, i.e. proceeds while bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Consequently, an entity recognises such sales proceeds and related costs in profit or loss.

  The amendments also clarify the meaning of 'testing whether an asset is functioning properly'. MFRS 116/IAS 16 now specifies this as assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes.

  If not presented separately in the statement of comprehensive income, the financial statements shall disclose the amounts of proceeds and cost included in profit or loss that relate to items produced that are not an output of the entity's ordinary activities, and which line item(s) in the statement of comprehensive income include(s) such proceeds and cost.

  The amendments are applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments.

  The entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings (or other component of equity, as appropriate) at the beginning of that earliest period presented.

- The amendments to MFRS 137/IAS 37 'Onerous Contracts – Cost of Fulfilling a Contract' specify that the 'cost of fulfilling' a contract comprises the 'costs that relate directly to the contract'. Costs that relate directly to a contract consist of both the incremental costs of fulfilling that contract, as well as an allocation of other costs that relate directly to fulfilling contracts. The amendments also clarify that before recognising a separate provision for an onerous contract, impairment loss that has occurred on assets used in fulfilling the contract should be recognised.

  The amendments shall be applied retrospectively and apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments.

Comparatives are not restated.

Instead, the entity shall recognise the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings or other component of equity, as appropriate, at the date of initial application.

- Annual Improvements to MFRS/IFRS Standards 2018–2020 (Effective date 1 January 2022)
  - The following improvements were finalised in May 2020:
  - MFRS 9/IFRS 9 Financial Instruments – clarifies which fees should be included in the 10% test for derecognition of financial liabilities.
  - MFRS 16/IFRS 16 Leases – amendment of illustrative example 13 to remove the illustration of payments from the lessor relating to leasehold improvements, to remove any confusion about the treatment of lease incentives.
  - MFRS 1/IFRS 1 First-time Adoption of International Financial Reporting Standards – allows entities that have measured their assets and liabilities at carrying amounts recorded in their parent's books to also measure any cumulative translation differences using the amounts reported by the parent. This amendment will also apply to associates and joint ventures that have taken the same MFRS 1/IFRS 1 exemption.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

Effective for annual period beginning on/after January 1, 2023

- Amendments to MFRS 101/IAS 1 - Disclosure of accounting policy information - require entities to disclose their material rather than their significant accounting policies. (Effective date 1 January 2023)
- Amendments to MFRS 108/IAS 8 - Definition of accounting estimates - clarifies how companies should distinguish changes in accounting policies from changes in accounting estimates (Effective date 1 January 2023)
- The amendments to MFRS 101/IAS 1 'Classification of Liabilities as Current or Non-current' affect only the presentation of liabilities as current or non-current in the statement of financial position and not the amount or timing of recognition of any asset, liability, income or expenses, or the information disclosed about those items (Effective date 1 January 2023).

  The amendments clarify that the classification of liabilities as current or non-current is based on rights that are in existence at the end of the reporting period, specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability, explain that rights are in existence if covenants are complied with at the end of the reporting period, and introduce a definition of 'settlement' to make clear that settlement refers to the transfer to the counterparty of cash, equity instruments, other assets or services.

The adoption of the above amendments will not have significant impact on the Company's financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

3.1 Basis of accounting

The financial statements of the Company have been prepared under the historical cost convention unless otherwise stated in the accounting policies mentioned below. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

3.2 Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. In estimating the fair value of an asset or a liability, the Company takes into account the characteristics of the asset or liability if market participants would take those characteristic into account when pricing the asset or a liability at the measurement date. Fair value for measurement and/or disclosure purposes in these financial statements is determined on such a basis, except for any share-based payment transactions that are within the scope of MFRS 2/IFRS 2, leasing transactions that are within the scope of MFRS 16/MFRS 117/IFRS 16/IAS 17, and measurements that have some similarities to fair value but are no fair value, such as net realisable value in MFRS 102/IAS 2 or value-in-use in MFRS 136/IAS 36.

In addition, for financial reporting purposes, fair value measurements are categorised into Level 1, 2 or 3 based on the degree to which the inputs to the fair value measurements are observable and the significance of the inputs to the fair value measurement in its entirety, which are described as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the entity can access at the measurement date;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability, either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

3.3 Classification of assets and liabilities into current and non-current

In the accompanying statement of financial position, assets and liabilities maturing within twelve months are classified as current items and those maturing in more than twelve months are classified as non-current items.

3.4 Intangible Assets

Intangible assets comprise expenditure on the exploration for and evaluation of oil and gas resources directly associated with an exploration well, including license acquisition and drilling costs, are initially capitalised as intangible assets until the results have been evaluated. During the exploration and evaluation phase, these costs are not amortized, although they are tested for impairment at least once a year and whenever indications of impairment are detected. Once the exploration and evaluation phase is completed, if no reserves are found, the amounts previously capitalized are recognized as an expense in the statement of profit or loss and other comprehensive income. If the exploration work does yield positive results, giving rise to commercially exploitable wells, costs are reclassified to "*Oil and gas properties*" at their carrying amount when this determination is made.

Exploration costs other than G&G costs ("Exploration rights and geology and geophysical costs"), excluding the costs of drilling exploration wells and exploration licenses, are recognized as an expense in the statement of profit or loss and other comprehensive income when incurred.

3.5. Property, Plant and Equipment

The Company uses the cost model by which items of property, plant and equipment are measured initially at acquisition cost.

The cost of property, plant and equipment includes their acquisition cost, all the costs directly related to the location of assets and all the costs to make them operational.

Additionally, if applicable, the cost of property, plant and equipment includes the present value of the expected disbursements necessary for any costs of dismantling and removing the item or restoring the site on which it is located, when such obligations are incurred under certain conditions. Subsequent changes to the measurement of the dismantling obligations and related liabilities resulting from changes in the estimated cash flows and/or in the discount rate are added to or deducted from the asset's carrying amount in the period in which they are incurred, except where the lower corrected value of the liability is greater than the carrying amount of the associated asset, in which case the surplus is recognized in the statement of profit or loss and other comprehensive income.

Borrowing costs that are directly attributable to the acquisition or construction of assets that require more than one year to be ready for use are capitalized as part of the cost of these assets, in accordance with the limits established in the applicable accounting rules.

Personnel expenses and other operating expenses directly attributable to the construction of the asset are also capitalized.

The costs of expansion, modernization or improvements leading to increased productivity, capacity or efficiency or to a lengthening of the useful lives of the assets are capitalized, as long as the general capitalization criteria are met.

Repair, upkeep and maintenance expenses are recognized in the statement of profit or loss and other comprehensive income as incurred. Furthermore, certain facilities require periodic reviews. In this respect, the assets subject to replacement are recognized specifically and are depreciated over the average term remaining until the next repairs are carried out.

Property, plant and equipment, other than those items relating to oil and gas exploration and production activities, are depreciated using the straight-line method on the basis of the acquisition cost of the assets less their estimated residual value, over the years of estimated useful life of the assets.

Depreciation of these assets starts when the assets become available for use.

Recognition of oil and gas exploration and production assets

The Company recognizes hydrocarbon exploration and production operations using accounting polices mostly based on the "successful efforts" method. Under this method, the various costs incurred are treated as follows for accounting purposes:

i. The costs incurred in the acquisition of new interests in areas with proved and unproved reserves are capitalized as incurred under "*Oil and gas properties*" item of property, plant and equipment.

ii. *Development expenditure* incurred in developing proved reserves and in processing and storing oil and gas (including costs incurred in drilling relating to productive wells and dry wells under development, oil rigs, recovery improvement systems, etc.) are recognized as assets under "*Oil and gas properties*".

iii. *Future field abandonment and dismantling costs* (environmental, safety, etc.) are estimated, on a field-by-field basis, and are capitalized at their present value when they are initially recognized under "*Oil and gas properties*" in assets in the statement of financial position. This capitalization is recorded against the caption "*Asset retirement obligations*" (see Note 14).

The costs capitalized as described above are depreciated as follows:

i. Investments in the acquisition of proved and probable reserves and common facilities are depreciated over the estimated commercial life of the field on the basis of the production for the period as a proportion of the proven and probable reserves.

ii. The costs incurred in surveys for the development and extraction of hydrocarbon reserves are depreciated over the estimated commercial life of the oil field on the basis of the relationship between the production of the period and the total of the proved and probable reserves of the field.

iii. Investments carried out in fields that are in the development or exploitation phase are not depreciated. These investments are tested for impairment at least once a year and whenever indications of impairment are detected.

The changes in estimated reserves are considered on a prospective basis in calculating depreciation.

3.6 Impairment of property, plant and equipment, intangible assets

In order to ascertain whether its assets have become impaired, the Company compares their carrying amount with their recoverable amount at least annually and whenever there are indications that the assets might have become impaired. Impairment is assessed on annual basis in accordance to Group's accounting policies. Recoverable amount is the higher of fair value less costs to sell and value in use. If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized as an expense in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined in case no impairment loss had been recognized for the asset in prior years.

3.7 Financial assets

Classification

The Company classifies its financial assets at the time it is initially recognised and is subsequently measured at either amortised costs, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL").

The classification of financial asset at initial recognition depends on the financial asset's contractual cash flow characteristics and the Company's business model for managing the financial assets. For assets measured at fair value, gains and losses will either be recorded in profit or loss or other comprehensive income ("OCI"). For investments in equity instruments that are not held for trading, this will depend on whether the Company has made an irrevocable election at the time of initial recognition to account for the equity investment at FVOCI.

The Company reclassifies debt investments when and only when its business model for managing those assets change.

Recognition and initial measurement

At initial recognition, with the exception of trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient, the Company initially measures a financial asset at its fair value plus, in the case of a financial asset not at FVTPL, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are expensed in profit or loss. Trade receivables that do not contain a significant financing component or for which the Company has applied the practical expedient is measured at the transaction price as determined under MFRS 15/IFRS 15.

Financial assets with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

Subsequent measurement

Subsequent measurement of debt instruments depends on the Company's business model for managing the asset and the cash flow characteristics of the asset. There are three measurement categories into which the Company classifies its debt instruments:

a) Debt instruments

i. Amortised cost

Assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortised cost. Interest income from these financial assets is included in finance income using the effective interest rate method. Any gain or loss arising on derecognition of the Company's financial assets are recognised directly in profit or loss and presented in other operating gains/(losses). Impairment losses are presented as separate line item in the statement of profit or loss and other comprehensive income.

ii. FVTPL

Assets that do not meet the criteria for amortised cost or FVOCI are measured at FVTPL. A gain or loss on a debt investment that is subsequently measured at FVTPL is recognised in profit or loss and presented net within other operating gains/(losses) in the period in which it arises.

b) Equity instrument

FVOCI

Assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Movements in the carrying amount are taken through OCI, except for the recognition of impairment gains or losses, interest revenue and foreign exchange gains and losses which are recognised in profit or loss. When the financial asset is derecognised, the cumulative gain or loss previously recognised in OCI is reclassified from equity to profit or loss and recognised in other operating gains/(losses). Interest income from these financial assets is included in finance income using the effective interest rate method. Foreign exchange gains and losses and impairment expenses are presented in other operating gains/(losses). When it is deemed to be material in nature, the impairment expenses shall be presented as separate line item in the statement of profit or loss and other comprehensive income.

Impairment of financial assets

The Company assesses on a forward looking basis the expected credit losses ("ECL") associated with its debt instruments carried at amortised cost. The amount of the expected credit losses is updated at the end of each reporting period to reflect changes in credit risk since initial recognition of the respective financial instrument.

The expected credit losses on these financial assets are estimated using a provision matrix based on the Company's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. For all other financial instruments, the Company recognises lifetime ECL when there has been a significant increase in credit risk since initial recognition. However, if the credit risk on the financial instrument has not increased significantly since initial recognition, the Company measures the loss allowance for that financial instrument at an amount equal to 12 month ECL.

Lifetime ECL represents the expected credit losses that will result from all possible default events over the expected life of a financial instrument. In contrast, 12 month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

Significant increase in credit risk

The Company considers the probability of default upon initial recognition of asset and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. To assess whether there is a significant increase in credit risk, the Company compares the risk of a default occurring on the asset as at the reporting date with the risk of default as at the date of initial recognition. It considers available reasonable and supportable forward looking information that includes historical default rate, internal and external credit rating (as applicable), actual or expected changes in economic and regulatory environment that are expected to cause a significant change to the debtor's ability to meet its obligations.

A significant increase in credit risk is presumed if a debtor become inactive, indication of consistent delay in making contractual payments that are long past due with history of default or the debtor is expected to/or is experiencing significant financial difficulties and cash flow problems.

Derecognition of financial assets

Financial assets are derecognised when the contractual rights to receive cash flows from the financial assets have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Any gain or loss arising on derecognition is recognised directly in profit or loss and presented in other gains/(losses) together with foreign exchange gains and losses.

3.8 Financial liabilities

Classification

Financial liabilities are classified according to the substance of the contractual arrangements entered into and the definitions of a financial liability. Management determines the classification of financial liabilities at initial recognition.

Financial liabilities are recognised in the statements of financial position when, and only when, the Company become a party to the contractual provisions of the financial instrument. The Company classifies all its financial liabilities as other financial liabilities.

Recognition and initial measurement

Trade and other payables are recognised initially at fair value net directly attributable transaction costs and subsequently measured at amortised cost using the effective interest method.

Loans and borrowings are recognised initially at fair value, net of transaction costs incurred and subsequently measured at amortised cost using the effective interest method. Borrowings are classified as current liabilities unless the Company have an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

Derecognition of financial liabilities

A financial liability is derecognised when the obligation under the liability is extinguished. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognised in the statements of comprehensive income.

3.9 Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount presented in the statement of financial position when there is a legally enforceable right to offset the recognised amounts and there is an intention to settle on a net basis, or realise the asset and settle the liability simultaneously. The legally enforceable rights must not be contingent on future events and must be enforceable in the normal course of business and in the event of default, insolvency or bankruptcy.

3.10 Cash and cash equivalents

The Company classifies under "*Cash and cash equivalents*" in the statement of financial position liquid financial assets, deposits or financial assets that can be converted into a known amount of cash three months from initiation to maturity and that are subject to an insignificant risk of changes in value.

3.11 Trade and other receivables

Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, where they are recognised at fair value plus transaction costs. Other receivables are recognised initially at fair value plus transaction costs. The impairment policy for trade receivables is in accordance with that for impairment of financial assets as described in Note 3.7 to the financial statements.

3.12 Provisions and contingent liabilities

In accordance with prevailing accounting standards, the Company makes a distinction between:

a) Provisions: present obligations, either legal or assumed by the Company, arising from past events, the settlement of which is probable to give rise to an outflow of resources the amount and timing of which are uncertain; and

b) Contingent liabilities: possible obligations that arise from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more future events not wholly within the control of the Company, or present obligations arising from past events, the amount of which cannot be measured with sufficient reliability or whose cancellation is not likely to give rise to an outflow of resources embodying future economic benefits.

These provisions are recognized when the liability or obligation giving rise to the indemnity or payment arises, to the extent that its amount can be reliably estimated and it is probable that the commitment will have to be settled.

Contingent liabilities are not recognized as provisions in the financial statements. Notwithstanding the above, whenever it is deemed as non-remote that settlement of such a liability will give rise to an outflow of resources, the existence of these liabilities is disclosed.

3.13 Asset Retirement Obligation ("ARO")

The fair values of the statutory, contractual or legal obligations associated with the retirement and reclamation of tangible long-lived assets are recorded when incurred and when a reasonable estimate of this amount can be made, with a corresponding increase to the carrying amount of the related assets. The increase to capitalised costs is amortised to profit and loss on a basis consistent with the depreciation, depletion and amortisation of the underlying assets. Subsequent changes in the estimated fair value of the ARO are capitalised and amortised over the remaining useful of the underlying asset.

The ARO liabilities are carried on the statement of financial position at their discounted present value and are accreted over time for the change in their present value, with this accretion charge recognised in profit and loss.

Actual expenditure incurred are charged against the accumulated obligation. Any difference between the recorded ARO and the actual retirement costs incurred is recorded as a gain or loss in the settlement period.

3.14 Revenues and expenses recognition

Revenue associated with the sale of crude oil and natural gas are recognised when control of the goods has transferred, being at the point the crude oil and natural gas exiting from the Company's storage tanks into the customer's storage tank.

Revenue from the sale of crude oil and natural gas are recognised based on the price in the agreement, that is the market price. Each of the field produces its own oil into distinctive tanks, and hence the benefit is derived from the lifted oil of the specific tanks distinctively and each lifting of entitled oil is a separate and distinctive performance obligation on its own as the benefits are directly derived from selling this.

Crude oil produced and sold by the Company below or above its working interest share in the related resource properties, results in production under-lifting or over-lifting.

The Company has adopted the entitlement method in measuring the under-lifting and over-lifting whereby they were measured at the fair value. Under-lifting is recorded as part of the "*Trade and other receivables*" in the statement of financial position and "*Change in underlift*" in the statement of profit and loss and other comprehensive income. Over-lifting is recorded as part of the "*Trade and other payables*" in the statement of financial position and presented as "*Supplies*" in the statement of profit or loss and other comprehensive income, along with purchases made during the year.

Under-lifting is reversed when the crude oil is lifted and sold, with the sales proceeds recorded as revenue and the cost of the inventory expensed. Over-lifting is reversed when sufficient volumes are produced to make up the overlifted volume.

The Company's operations are governed by the PSC. Under the PSC, revenues are derived from cost recovery oil and gas and profit oil and gas. Generally, cost recovery oil and gas allows the Company to recover its capital and production costs and, as appropriate, the costs carried by the Company on behalf of relevant national oil company from production. Profit oil and gas is allocated to the national oil company and contract parties in accordance with the terms of the respective PSCs.

Interest income is accrued on a time proportion basis, by reference to the principal outstanding and the effective interest rate applicable.

An expense is recognized when there is a decrease of economic benefits associated to a reduction of an asset, or an increase in a liability, whichever can be measured reliably.

3.15 Financing costs

Financing costs comprise interest payable on borrowings and any accretion in provision due to the passage of time.

3.16 Income Tax

The Company recognizes in the statement of profit or loss and other comprehensive income for the year the accrued tax on the Company's income, which is calculated taking into account the differences between the timing of recognition for accounting purposes and tax purposes of the transactions and other events in the current year recognized in the financial statements, giving rise to temporary differences and, therefore, to the recognition of certain deferred tax assets and liabilities in the statement of financial position. These amounts are recognized by applying to the temporary differences the tax rate that is expected to apply in the period when the asset is realized, or the liability is settled.

Taxation on profit for the year is calculated at the current tax rate based on the estimated chargeable income for the year computed under the Barbados tax legislation and Vietnam Income Tax regulation (where PSC is taxed).

Deferred tax liabilities are recognized for all taxable temporary differences, unless the temporary difference arises from the initial recognition of goodwill.

Deferred tax assets recognized for temporary differences and other deferred tax assets (tax losses and tax deductions carry forwards) are recognized when it is considered probable that the Company will have sufficient taxable profits in the future against which the deferred tax asset can be utilized. Deferred tax assets relating to the carry forward of unused tax losses are recognised to the extent that it is probable that future taxable profit will be earned against which the unused tax losses can be utilised.
The accrued income tax expense includes both the deferred income tax expense and the current income tax expense, which is taken to be the amount payable (or refundable) in relation to the taxable net income for the year (see Note 16).

"*Income tax expense*" in the statement of profit or loss and other comprehensive income includes both the accrued income tax expense and the net provisions recognized in the year for uncertain tax position, insofar as the latter relate to income tax.

Current and deferred taxes are recognized outside statement of profit or loss and other comprehensive income if they are related to items that are recognized outside the statement of profit or loss and other comprehensive income. Those entries related to items recognized under "Adjustments for changes in value" are recognized under that heading and those recognized directly in equity are recognized within the equity.

3.17 Foreign Currency

The Company's functional currency and presentation currency is United States dollars. Transactions in currencies other than the functional currency are deemed to be 'foreign currency transactions' and are translated to the functional currency by applying the exchange rates prevailing at the date of the transaction. At each year end, the foreign currency monetary items on the statement of financial position are measured applying the exchange rate prevailing at that date and the exchange rate differences arising from such measurement are recorded as "foreign exchange gain/(loss)" within "Financial result" in the statement of profit or loss and other comprehensive income in the year incurred.

3.18 Leases

A lease is an agreement whereby the lessor conveys to the lessee in return for a payment, or series of payments, the right to use an asset for an agreed period of time.

a) Leases in which the Company is a lessee

From January 1, 2019, leases are recognised as right-of-use ("ROU") asset and a corresponding liability at the date on which the leased asset is available for use by the Company (i.e. the commencement date).

Lease terms

In determining the lease term, the Company considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not to be terminated).

The Company reassess the lease term upon the occurrence of a significant event or change in circumstances that is within the control of the Company and affects whether the Company is reasonably certain to exercise an option not previously included in the determination of lease term, or not to exercise an option previously included in the determination of lease term. A revision in lease term results in re-measurement of the lease liabilities.

ROU assets

ROU assets are initially measured at cost comprising the following:

- The amount of the initial measurement of lease liability;
- Any lease payments made at or before the commencement date less any lease incentive received;
- Any initial direct costs; and
- Decommissioning or restoration costs.

Upon lease commencement, the Company measures the ROU asset using a cost model. ROU assets are depreciated over the lease term on a straight-line basis.

Lease liabilities

Lease liabilities are initially measured at the present value of the lease payments that are not paid at that date. The lease payments include the following:

- Fixed payments (including in-substance fixed payments), less any lease incentive receivable;
- The exercise price of an extension options if the Company is reasonably certain to exercise that option; and
- Payments of penalties for terminating the lease, if the lease term reflects the Company exercising that option.

Lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be readily determined for leases in the Company, the Company's incremental borrowing is used. This is the rate that the individual lessee would have to pay to borrow the funds necessary to obtain an asset of similar value to the ROU in a similar economic environment with similar term, security and conditions.

Lease payments are allocated between principal and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

The Company presents the lease liabilities as a separate line item in the statement of financial position. Interest expense on the lease liability is presented within the finance cost in the statement of profit or loss and other comprehensive income.

Reassessment of lease liabilities

The Company is exposed to potential cash flows change if there is a change in lease term due to the Company exercises an extension or termination option, which are not included in the lease liability until the Company is reasonably certain to exercise the option.

When the option is exercised, the lease liabilities are remeasured by discounting the revised lease payments using revised discount rate.

Short-term leases and leases of low-value assets

Short-term leases are leases with a lease term of 12 months or less. Low-value assets comprise IT equipment, small items of office furniture and vehicles. Payment associated with short-terms lease of equipment, vehicles and vessels and all leases of low-value assets are recognised on a straight-line basis as an expense in the statement of profit or loss and other comprehensive income.

Until December 31, 2018, a lease is recognised as a finance lease if it transfers substantially to the Company all the risks and rewards incident to ownership. All leases that do not transfer substantially all the risk and rewards are classified as operating leases.

Finance leases

Assets acquired by way of finance leases are stated at an amount equal to the lower of their fair values and the present value of the minimum lease payments at the inception of the leases, less accumulated depreciation and impairment losses. The corresponding liability is included in the statement of financial position as part of "Trade and other payables" for current portion and "Long-term lease obligation" for non-current portion. In calculating the present value of the minimum lease payments, the discount factor used is the interest rate implicit in the lease, when it is practicable to determine; otherwise, the Company's incremental borrowing rate is used.

Lease payments are apportioned between the finance charges and the reduction of the outstanding liability. Finance costs, which represent the difference between the total leasing commitments and the fair value of the assets acquired, are recognised as finance expenses in the statement of comprehensive income over the term of the relevant lease so as to produce a constant periodic rate of charge on the remaining balance of the obligations for each accounting period.

The depreciation policy for capital lease is in accordance with that for depletion, depreciation and amortisation as described in Note 3.5.

Operating leases

Leases where substantially all the rewards and risks of ownership of assets remain with the lessor are accounted for as operating leases. Rental on operating leases are charged to profit or loss on a straight line basis in the financial year in which they are incurred.

3.19 Inventories

Inventories are valued at the lower of cost less provision for obsolescence and net realisation value. The cost is calculated as average cost, and includes the acquisition costs after deduction of any discounts, rebates or other similar items, such as interest incorporated into the nominal amount, plus any additional costs incurred to bring the goods to a saleable condition, such as transport, import duties, insurance and other costs directly attributable to the acquisition of inventories. The inventories of the Company are the Company's share of purchased materials held under the joint operations agreements for utilisation in conducting the affairs of the joint operations.

The Company carries out annual material review of inventories at the end of the year, recording the appropriate value correction with a charge to results when inventories are obsolete and no foreseeable future usage. When the circumstances that previously caused the value correction cease to exist, the amount is reversed.

3.20 Transactions with related parties

The Company performs all its operations with related parties at agreed terms and prices, which is why management considers that there are no significant risks from this aspect from which future liabilities may arise.

3.21 Joint Operation Agreements

The Company recognises its share of jointly controlled assets and jointly incurred liabilities on the basis of the percentage of ownership, as well as jointly controlled assets and liabilities incurred as a result of the joint operation agreements.

The Company recognises the proportion of income generated and expenses incurred under the joint operation agreement in the statement of profit or loss and other comprehensive income, in addition to the expenses incurred in relation to the interest in the joint operation.

3.22 Elements of environmental nature

Environmental assets are defined as assets that are used on a lasting basis in the Company's business activity, the main purpose of which is to minimise the impact on the environment and to protect and improve the environment, including the reduction or elimination of future pollution.

Property, plant and equipment of an environmental nature are identified on the basis of the nature of the Company's activities, in accordance with the technical criteria of the Repsol Group based on the guidelines on this matter issued by the American Petroleum Institute (API).

Non-current assets of an environmental nature and the related accumulated depreciation are recognised in the statement of financial position, together with the other items of property, plant and equipment, classified according to their nature.

The cost of these items of property, plant and equipment and the depreciation and amortisation methods used are determined in accordance with the provisions of Note 3.5 and 3.6 of these financial statements.

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

4.1 Critical judgements in applying the Company's accounting policies

In the process of applying the Company's accounting policies, which are described in Note 3 above, management is of the opinion that there are no instances of application of judgement which are expected to have a significant effect on the amounts recognised in the financial statements.

4.2 Key sources of estimation uncertainty

The information included in these financial statements is the responsibility of the management of the Company.

In the financial statements for the year 2020, 2019 and 2018, on occasions estimations made by the management of the Company have been used to evaluate some of the assets, liabilities, income, expenses and commitments that are recorded in the accounts. Basically, those estimations, made according to the best information available, relate to:

- Assessment of potential impairment losses on certain assets
- Estimation of crude oil and gas reserves and resources
- Provisions for litigation, dismantling and other contingencies
- Calculation of income tax, tax credit and deferred tax assets
- Calculation of expected credit loss

4.2.1 Assessment of potential impairment losses on certain assets

In order to ascertain whether its assets have become impaired, the Company compares the carrying amount with the recoverable amount at least annually and whenever there are indications that an asset might have become impaired ("impairment test"). If the recoverable amount of an asset is estimated to be less than its net book value, the carrying amount of the asset is reduced to its recoverable amount, and an impairment loss is recognized in the statement of profit or loss and other comprehensive income.

After an impairment loss has been recognized, amortization charges are calculated prospectively on the basis of the reduced carrying amount of the impaired asset.

On the occurrence of new events, or changes in existing circumstances, which prove that an impairment loss recognized on a prior date no longer exists or has decreased, a new estimate of the recoverable value of the corresponding asset is developed, to determine whether it is appropriate to reverse the impairment losses recognized in previous periods.

In the event of a reversal of an impairment previously recorded, the carrying amount of the asset is increased to the revised estimate of its recoverable value, so that the increased carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognized for the asset in prior years.

For the "impairment test", assets are grouped into cash-generating units (CGUs), to the extent that such assets, when individually considered, do not generate cash inflows that are independent of the cash inflows from other assets or CGUs. The grouping of assets into the various CGUs requires the use of professional judgments and the determination, among other criteria, of the business segments and geographic areas in which the Company operates. In the upstream segment, each CGU corresponds to one of the various contractual exploration areas widely known as "blocks" exceptionally. There is only one block known as Block B46 Cai Nuoc in the Company.

The recoverable amount is the higher of fair value less costs of sale and value in use.

The methodology used by the Company to estimate the recoverable amount of assets is, in general, the value in use calculated by discounting to present value the future cash flows expected to be derived from the operation of these assets.

The cash flow projections are based on the best available estimates of the CGUs' income and expenses using sector forecasts, prior results and the outlook for the business's performance and market's development:

- Macroeconomic variables are those used in the preparation of the budgets. The macroeconomic framework for the countries in which the Group operates takes into consideration variables such as inflation, GDP, exchange rate, etc. and is prepared on the basis of the content of internal reports that use in-house estimates, based on updated external information of relevance (forecasts prepared by consultants and specialized entities).

- The oil and natural gas price paths used for the impairment test are our own estimates, although they are consistent or in line with the view of prices established by the various international benchmark agencies, including the International Energy Agency ("IEA"). The paths are developed on the basis of available macroeconomic, financial and market information and the forecasts provided by analysts and they consider scenarios for the energy transition and decarbonisation of the economy that are consistent with the commitments assumed to achieve the objectives of the Paris Climate Summit.

In particular, crude oil and gas prices are calculated by analysing key market variables and their foreseeable trend, including our own forecasts of the balance of supply and demand of energy and prices. The longer-term vision is also explained by monitoring other variables such as: the decline, the current CAPEX, the financial sustainability of companies in the sector to certain price environments, and the dynamics in OPEC countries in terms of fiscal sustainability. Econometric models of prices are made with all these elements, which are compared with both public and private external forecasts.

i. To estimate near-term price trends, we basically use forecast reports produced by a selection of, investment banks, macro consultants and international benchmark agencies are taken into account.

ii. The sources that present a sufficiently detailed analysis of long-term forecasts are the macro consultants and benchmark agencies (IEA and EIA), which also carry out detailed studies of supply, demand and price forecasts under different scenarios

The assumptions for the main price references for 2018 are as follows:

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Brent ($/ barrel)	65	70	75	81	86	89	92	94	97

The assumptions for the main price references for 2019 are as follows:

	2020	2021	2022	2023	2024	2025	2026-2027
Brent ($/ barrel)	65	69	70	71	72	74	81

In 2020, in view of the situation in the commodity markets and in particular the social and economic consequences of the COVID-19 pandemic and the foreseeable development of the energy transition, the Group reviewed its expectations of future oil and gas prices, modifying the price paths defined at the end of 2019 to bring them into line with the new scenario.

It should be noted that these estimates were made in an environment of high uncertainty, marked by the scenarios of emerging from the COVID-19 crisis, by the dynamics of the energy transition and decarbonisation of the economy and, in short, by their possible impacts on the Oil & Gas markets.

- The Brent's path was revised downwards in the short and medium term (until 2024) as a result of a contraction in the demand for oil never seen before and a reaction of supply that was insufficient to adjust to the low demand, despite the fact that the OPEC+ made the biggest production cut in its history and other producers have also taken heavy cuts.

- The Henry Hub path was revised upwards for 2021, due to the drop in gas production and the boost in the demand for gas for the electricity industry and electricity generation in the US, and the path was revised downwards in the medium and long term due to the expectation of greater penetration of renewable energies on a global scale and the consolidation of excess supply in the face of falling global demand.

The assumptions for the main price references for 2020 are as follows:

	2021	2022	2023	2024	2025	2026-2027
Brent ($/ barrel)	49	55	58	62	67	59

Future cash flows are discounted to their present value at a specific rate for each CGU, determined based on the currency of its cash flows and the risks associated with them. The discount rate used by the Company is the weighted average cost of capital employed for each country and business.

Cash flows are estimated on the basis of the outlook for their key variables in accordance with the expectations reflected in the annual budget and in the strategic plans for each business, in line with the new scenario of energy transition and decarbonization of the economy.

The discount rates used in 2020, 2019 and 2018 are as follows:

2020	2019	2018
7.36%	7.62%	8.16%

Valuations of the production assets of Exploration and Production (Upstream) use cash flow projections for a period that covers the economically productive useful lives of the oil and gas fields, limited by the contractual expiration of the operating permits, agreements or contracts. The general principles applied to determine the variables that most affect the cash flows of this business are described below:

- Oil and gas sales prices. The international benchmark price used by the Group are: Brent and HH (Henry Hub).

- Reserves, resources and production profiles. Production profiles are estimated on the basis of output levels at existing wells and the development plans in place for each productive field. Further information on estimation of crude oil and gas reserves and resources are disclosed in Note 4.2.2.

- Operating expenses and capital expenditure. These are calculated for the first year on the basis of the Group's annual budget and thereafter in keeping with the asset development programs, applying an escalation factor for operating expenses and investments basically of -1% to 1% (1%-1.5% in 2019, 2% in 2018).

4.2.2 Estimation of crude oil and gas reserves and resources

The process of estimating oil and gas reserves is a key component of the Company's decision-making process. Oil and gas reserve estimates are used to calculate depreciation and amortization charges applying the unit-of-production ratio method and to assess the recoverability of the investments in the assets. Changes in reserve and resources could have a significant impact on the result.

The reserves are classified as follows:

a. Proved reserves: Proved reserves are those quantities of crude oil, natural gas and natural gas liquids that, with the information available to date, are estimated to be recoverable with reasonable certainty. There should be at least a 90% probability that the amounts recovered will equal or exceed the 1P estimate.

b. Probable reserves: Probable reserves are those additional reserves that, together with proved reserves, make up scenario 2P. There should be at least a 50% probability that the amounts recovered will equal or exceed the 2P estimate. This scenario reflects the best estimate of the reserves.

c. Developed reserves: Proved or probable quantities that are expected to be recovered from existing wells and facilities.

d. Undeveloped reserves: Proved or probable quantities that are expected to be recovered through future investments.

To estimate oil and gas reserves and resources, the Company uses the criteria established by the "SPE/WPC/AAPG/SPEE/SEG/ SPWLA/EAGE Petroleum Resources Management System", commonly referred to by its acronym SPE-PRMS (SPE standing for Society of Petroleum Engineers).

4.2.3 Provisions for litigation, dismantling and other contingencies

The Company makes judgements and estimates that affect the recognition and measurement of provisions for litigation, decommissioning and other contingencies. The final cost of settling complaints, claims and lawsuits may vary due to differences in the identification of dates, interpretation of rules, technical opinions and assessments of the amount of damages and liabilities.

The calculations to recognize provisions for the cost of decommissioning its oil and gas production operations are complex, on account of the need to initially recognize the present value of the estimated future costs and to adjust this figure in subsequent years in order to reflect the passage of time and changes in the estimates due to changes in the underlying assumptions used as a result of technological advances and regulatory changes, economic, political and environmental security factors, as well as changes in the initially-established schedules or other terms. The decommissioning provisions are updated regularly to reflect trends in estimated costs and the discount rates. These discount rates take into account the risk-free rate, by term and currency, country risk and the cash flow projection period. Specifically, the weighted average rate used by the Company was 2.36% (2019: 3.19%; 2018: 4.70%).

Additionally, the Company makes judgments and estimates in recording costs and establishing provisions for environmental clean-up and remediation costs, which are based on current information regarding costs and expected plans for remediation based on applicable laws and regulations, the identification and assessment of the effects on the environment, as well as sanitation technologies.

Therefore, any change in the factors or circumstances related to provisions of this nature, as well as changes in laws and regulations could, as a consequence, have a significant effect on the provisions recognized for these costs.

4.2.4 Calculation of income tax, tax credit and deferred tax assets

The appropriate assessment of the income tax expense is dependent on several factors, including estimates of the timing and realization of deferred tax assets and the timing of income tax payments. Collections and payments may be materially different from these estimates as a result of changes in the expected performance of the Company's businesses or in tax regulations or their interpretation, as well as unforeseen future transactions that impact the Company's tax balances.

Deferred tax assets are only recognized when it is considered probable that the Company will have sufficient taxable income in the future against which they can be utilized.

Deferred tax assets are reviewed when there are indications of impairment, and in any event once a year, to verify that they still qualify for recognition and they are considered to be recoverable in the future, and the appropriate adjustments are made on the basis of the outcome of the analyses performed. These analyses are based on: (i) assumptions made to analyse the existence or otherwise of sufficient future earnings for tax purposes that might offset the tax losses or apply existing tax credits, based on the approach used to ascertain the presence of indications of impairment on its assets; (ii) the assessment of earnings estimates for the Company in accordance with the Company's business plans and the Group's overall strategic plan; and (iii) the statute of limitations period and other utilization limits imposed under prevailing legislation in the country for the recovery of the tax credits.

4.2.5 Calculation of expected credit loss

The Company does not have any trade receivable as at year end. The remaining financial assets are individually monitored.

As a general criterion, 180 days past due is used to define credit-impaired financial instruments (in the absence of other evidence of default such as bankruptcy, etc).

The expected credit loss on financial instruments is calculated based on the stage of the debtor's credit risk statement.

• Phase 1: At the time of initial recognition, the expected credit loss is calculated with the probability of default in the first 12 months. In the case of trade receivables, the calculation is spread over the life of the instrument, in accordance with the accounting standard.
• Phase 2: When the instrument undergoes a significant increase in risk, the expected loss is calculated with the probability of default for the entire life of the instruments.
• Phase 3: When the instrument is already impaired, the expected loss for the entire life of the instrument is calculated and, in the event that interest accrues, it is calculated on the net balance of the provision of credit loss.

The assessment of the impairment of the value of the financial assets, to which the expected loss model is applicable, is calculated according to the following formula:

Expected credit loss = Probability of default x Exposure x Severity

Probability of default is calculated individually for each trade debtor according to the solvency models approved by the Repsol Group, except for individuals, from whom an average default rate is used. The models take into account quantitative information (economic-financial variables of the customer, external and internal payment behaviour, etc.), quantitative information (sector of activity, macroeconomic data on the country, etc.) and market sensitivity variables (e.g. price evolution). An internal rating and an associated probability of default are obtained for each debtor, according to the models.

Exposure is calculated taking into account the total amount of outstanding credit and a potential future exposure according to the available risk limit.

Severity reflects the percentage of unrecovered exposure in the event of default, taking into account whether or not such exposure is guaranteed, and is based on the behaviours of customers.

5. RISK MANAGEMENT

The Company is exposed to various risks that are particular to its core business of exploration, development and production. These risks arise in the normal course of the Company's business.

The Company's goal in risk management are to ensure that the management understands, measures and monitors the various risks that arise in connection with their operations. Policies and guidelines have been developed to identify, analyse, appraise and monitor the dynamic risks facing by the Company. Based on this assessment, each business unit adopts appropriate measures to mitigate these risks in accordance with the business unit's view of the balance between risk and reward.

The Company has exposure to liquidity risk, credit risk, commodity price risk and interest rate risk arising from its use of financial instruments in the normal course of the Company's businesses.

5.1 Liquidity risk

The Company actively manages its debt maturity profile, operating cash flows and the availability of funding to ensure that all refinancing, repayment and funding needs are met. As part of its overall prudent liquidity management, the Company maintains sufficient levels of cash to meet its working capital requirements. In addition, the Company strives to maintain available banking facilities of a reasonable level to its overall debt position.

The table below summarises the maturity profile of the Company's financial liabilities at the balance sheet date based on contractual undiscounted repayment obligations:

	USD'000 2020	USD'000 2019	USD'000 2018
Due to related parties			
- Less than one year	2,152	3,066	1,531
Trade and other payables			
- Less than one year	405	384	1,196
Total	2,557	3,450	2,727

5.2 Credit risk

Credit risks, or the risk of counterparties defaulting, are controlled by the application of credit approvals, limits and monitoring procedures. The Company is exposed to credit risk, which is the risk that a customer or counterparty will fail to perform an obligation or settle a liability, resulting in credit loss to the Company. The Company's concentration of credit risk is mitigated by dealing with generally credit worthy large international oil and gas companies.

The Company minimises credit risk by entering into contracts with highly credit rated counterparties. Potential counterparties are subject to credit assessment and approval prior to any transaction being concluded and existing counterparties are subject to regular reviews, including re-appraisal and approval of granted limits. The creditworthiness of counterparties is assessed based on an analysis of all available quantitative and qualitative data regarding business risks and financial standing, together with the review of any relevant third party and market information. Reports are regularly prepared and presented to the management that cover the Company's overall credit exposure against limits and securities, exposure by segment and overall quality of portfolio.

The maximum exposure to credit risk for the Company is represented by the carrying amount of each financial asset. A significant portion of these receivables are regular customers that have been transacting with the Company.

The Company uses ageing analysis and credit term review to monitor the credit quality of the receivables. Any customers exceeding their credit limit are monitored closely.

The expected credit loss for trade and other receivables at December 31, 2020, 2019 and 2018 are immaterial.

The Company's exposure to credit risk, according to the type of financial instrument, with no impairment recognized at December 31 for each of them, is broken down as follows and they are not due as at the respective year-end:

	USD'000 Gross	USD'000 Impairment	USD'000 Net
2020			
Trade and other receivables	3,276	-	3,276
Loan to related party	2,511	-	2,511
Cash and cash equivalents	949	-	949
Total	**6,736**	**-**	**6,736**
2019			
Trade and other receivables	4,140	-	4,140
Loan to related party	14,403	-	14,403
Cash and cash equivalents	1,000	-	1,000
Total	**19,543**	**-**	**19,543**
2018			
Due from related parties	1,939	-	1,939
Loan to related party	15,133	-	15,133
Cash and cash equivalents	1,372	-	1,372
Total	**18,444**	**-**	**18,444**

5.3 Commodity price risk

As a result of the development of operations and commercial activities, the Company's results are exposed to the volatility of the prices of oil, natural gas and their derivatives.

The Company monitors its exposure to market risk in terms of sensitivities. These are supplemented by other risk measures on those occasions when the nature of the risk positions requires so.

5.4 Interest rate risk

The Company is not exposed to significant interest rate risk.

5.5 Other risk

On March 11, 2020, the World Health Organization raised to the status of global pandemic the public health emergency caused by SARS-CoV-2 virus (commonly known as coronavirus, while COVID-19 denotes the disease caused by the virus). The rapid spread of COVID-19, on an international scale, has triggered an unprecedented healthcare, social and economic crisis that continues to evolve.

The economic impact of the pandemic, combined with pre-existing complications on the supply and demand side, has resulted in an exceptionally challenging pricing environment for oil and gas.

Even amid these difficult circumstances, the Company has sustained the safe operation of its business.

It is difficult to predict to what extent and for how long the impact of the pandemic will affect the Company's business in the future. The lower global demand for crude oil, gas and oil products as a result of the reduction in economic activity and, in particular, the restrictions to mobility, may have a negative impact on prices, production levels and sales volumes, the deterioration of global financial conditions may affect the cost of capital, liquidity or solvency on our customers and partners in joint operations, and so on.

6. FINANCIAL INSTRUMENTS

All the financial assets and financial liabilities of Company are measured at amortised costs. The following table analyses the financial assets and financial liabilities in the statement of financial position by the class of financial instruments to which they are assigned, and therefore by the measurement basis:

6.1 Classification of financial instruments

	USD'000 2020	USD'000 2019	USD'000 2018
Financial assets			
Amortised cost:			
Trade and other receivable	3,276	4,140	-
Due from related parties	-	-	1,939
Loan to related party	2,511	14,403	15,133
Cash and cash equivalents	949	1,000	1,372
Total	**6,736**	**19,543**	**18,444**
Financial liabilities			
Amortised cost:			
Due to related parties	2,152	3,066	1,531
Trade and other payables	405	384	1,196
Total	**2,557**	**3,450**	**2,727**

7. CAPITAL RISK MANAGEMENT

Capital management is defined as the process of managing the composition of the Company's debts.

The Company operates within clearly defined guidelines that are approved by Repsol, S.A., which is the ultimate holding company and it relies on the ultimate holding company for funding to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities as and when they fall due.

8. INTANGIBLE ASSETS

	USD'000 Total
Cost	
Balance at January 1, 2018	3
Additions	-
Balance at December 31, 2018	3
Additions	-
Balance at December 31, 2019	3
Additions	-
Balance at December 31, 2020	3
Amortization	
Balance at January 1, 2018	-
Amortization	1
Balance at December 31, 2018	1
Amortization	1
Balance at December 31, 2019	2
Amortization	1
Balance at December 31, 2020	3
Net carrying value	
Balance at December 31, 2018	**2**
Balance at December 31, 2019	**1**
Balance at December 31, 2020	**-**

The intangible assets mainly consist of the implementation cost of the SAP Project One.

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9. PROPERTY, PLANT AND EQUIPMENT

	USD'000 Oil and gas properties	USD'000 Admin assets	USD'000 Total
Cost			
Balance at January 1, 2018	37,418	87	37,505
Additions	2,767	-	2,767
Balance at December 31, 2018	**40,185**	**87**	**40,272**
Additions	1,085	-	1,085
Change in estimates for ARO	1,740	-	1,740
Balance at December 31, 2019	**43,010**	**87**	**43,097**
Additions	376	-	376
Change in estimates for ARO	(254)	-	(254)
Transfer/Disposal	-	(2)	(2)
Balance at December 31, 2020	**43,132**	**85**	**43,217**
Accumulated depletion/ depreciation			
Balance at January 1, 2018	(34,965)	(87)	(35,052)
Charge for the year	(315)	-	(315)
Balance at December 31, 2018	**(35,280)**	**(87)**	**(35,367)**
Charge for the year	(851)	-	(851)
Balance at December 31, 2019	**(36,131)**	**(87)**	**(36,218)**
Charge for the year	(1,074)	-	(1,074)
Transfer/Disposal	-	2	2
Balance at December 31, 2020	**(37,205)**	**(85)**	**(37,290)**
Net carrying value			
Balance at December 31, 2018	**4,905**	-	**4,905**
Balance at December 31, 2019	**6,879**	-	**6,879**
Balance at December 31, 2020	**5,927**	-	**5,927**

The extension to the Block B46 Cai Nuoc Production Sharing Contract ("PSC") was granted on September 12, 2017 whereby both the crude oil and natural gas productions were each extended from February 16, 2017 and August 13, 2019 respectively to December 31, 2027.

The Company has taken out insurance policies to cover the risk of damage to its property, plant and equipment. The coverage of these policies is considered sufficient.

Fully depreciated property, plant and equipment amounted to $85 thousand at December 31, 2020 ($87 thousand in 2019).

At December 31, 2020 and 2019 the Company has no commitments to purchase property, plant and equipment.

10. JOINT OPERATIONS

A Unitisation agreement was signed between PETRONAS and Vietnam Oil & Gas Group ("Petrovietnam") on February 10, 2000 whereby it was agreed that East Bunga Kekwa - Cai Nuoc Field will be developed and exploited by the PM3 CAA Group and Block 46 Group, effective from June 10, 1998. Repsol Oil & Gas Malaysia Limited who is the PM3 operator is appointed to act as the unit operator.

The Company initially held a 33.15% interest in Block 46 Cai Nuoc (B46-CN). The East Bunga Kekwa-Cai Nuoc Unit Area is unitized between B46-CN PSC and PM3-CAA, with PM3-CAA PSC holding 75.95% and B46-CN PSC holding the remaining 24.05% of the Unit Area. On 12 September 2017, Vietnamese Government approved the Company to be entitled to an additional 36.85% share of the B46-CN since January 1, 2014. The Company now held 70% participation interest in B46-CN with the remaining 30% participation interest held by Petrovietnam Exploration Production Corporation Ltd.

In accordance with the terms by the joint operations, at the end of the 2020, 2019 and 2018 financial periods, the interest held by the Company in these investments are as follows:

			USD'000	
	Working Interest	2020 Revenue	2019 Revenue	2018 Revenue
B46-CN	70%	-	5,334	15,224
Total		-	5,334	15,224

The Company accounts for its investments in joint operations recording in its balance sheet the proportionate share of the jointly controlled assets and jointly incurred liabilities that corresponds based on its percentage of participation (working interest).

Likewise, the corresponding part of the income generated and the expenses incurred by the joint operation are recognized in the income statement.

11. TRADE AND OTHER RECEIVABLES

	USD'000 2020	USD'000 2019	USD'000 2018
Cash calls receivables from partners	3,276	4,140	-
Accounts receivables from partners (underlift)	5,482	1,841	762
Total	**8,758**	**5,981**	**762**

Talisman Vietnam Limited is exposed to credit risk, which is the risk that a customer or counterparty will fail to perform an obligation or settle a liability, resulting in financial loss to the Company. The maximum credit risk exposure associated with trade and other receivables is the carrying value.

Accounts receivables from partners refers to the oil product that the Company was entitled to, based on the production sharing contract, of which lifted by partners. At each reporting date, the amount is valued at the lower of current market value and fair value at the date of lifting.

Cash call receivables from partners refer to funding receivable from partners relating to Production Sharing Contract expenditures and working capital.

12. LOAN TO RELATED PARTY

	USD'000 TEHS	USD'000 RIF
Balance at January 1, 2018	**5,214**	-
Draws during the year	2,930	11,500
Repayments during the year	(1,224)	(3,500)
Interest during the year	65	148
Transfer of loan	(6,985)	6,985
Balance at December 31, 2018	-	**15,133**
Draws during the year	-	5,000
Repayments during the year	-	(6,000)
Interest during the year	-	270
Balance at December 31, 2019	-	**14,403**
Repayments during the year	-	(2,000)
Interest during the year	-	108
Transfer of loan – dividend payment	-	(10,000)
Balance at December 31, 2020	-	**2,511**

TEHS and RIF share a common ultimate holding company (Repsol, S.A.).

During 2018 the loan agreement with TE Holdings S.A.R.L had been transferred to Repsol International Finance B.V. ("RIF") with the same terms and conditions. Interest is based on a one-month London Inter Bank Offering Rate (LIBOR). On December 31, 2019, the balance of the loan principal was $14,385 thousand plus accrued interest $18 thousand.

On December 31, 2020, the balance of the loan principal was $2,510 thousand plus accrued interest $1 thousand.

On December 16, 2020, the Company declared a dividend to its parent company Fortuna International Petroleum Corporation ("FIPC") by way of transferring loan due from RIF of $10,000 thousand to FIPC.

13. TRADE AND OTHER PAYABLES

	USD'000 2020	USD'000 2019	USD'000 2018
Cash calls payable	-	-	1,168
Accrued liabilities	405	384	28
Total	**405**	**384**	**1,196**

Trade payables and others are unsecured and are usually paid within 30 days of recognition.

Carrying amount of current liabilities does not significantly differ from its fair value.

14. ASSET RETIREMENT OBLIGATION ("ARO")

ARO movement during 2020, 2019 and 2018 is as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Asset retirement obligation, beginning of year	2,423	652	1,078
Accretion	77	31	44
Revision in estimates	(254)	1,740	(470)
Asset retirement obligation, end of year	**2,246**	**2,423**	**652**

The estimated asset retirement obligation as at December 31, 2020 was $2,246 thousand ($2,423 thousand in 2019; $652 in 2018) and is expected to be incurred near the end of the respective term of the Company's Production Sharing Contract (2027).

The ARO has been discounted using a discount rate of 2.36% (2019: 3.19%; 2018: 4.70%).

Total accretion for the year ended December 31, 2020 of $77 thousand ($31 thousand in 2019; $43 thousand in 2018) has been included in interest (see note 17(e)).

15. SHARE CAPITAL

The Company's authorized share capital consists of an unlimited number of common shares without nominal or par value. Number of shares issued and outstanding were 12,000 as at December 31, 2020, in the amount of $12 thousand.

At December 31 2020, 2019 and 2018, Fortuna International Petroleum Corporation had a participation corresponding to 100% of the Company's share capital.

The shares of the Company are not listed on any Stock Exchange.

16. INCOME TAXES

	USD'000 2020	USD'000 2019	USD'000 2018
Tax expense attributable to profit is made up of:			
CURRENTCORPORATE INCOME TAX			
Foreign income tax paid	100	(34)	(3,794)
Over/(under) provision in prior years	251	96	(71)
Total	**351**	**62**	**(3,865)**
DEFERRED CORPORATE INCOME TAX			
Recognition of temporary difference	(1,780)	(403)	(743)
Under/(over) provision in prior years	-	(50)	-
Total	**(1,780)**	**(453)**	**(743)**
Total income tax expense	**(1,429)**	**(391)**	**(4,608)**

The Company accounts for income taxes using the tax liability method. As a result, the Company's income tax expense varies from the amount that would otherwise result from the application of the statutory income tax rates as set out below:

	USD'000 2020	USD'000 2019	USD'000 2018
Profit/(Loss) before income tax	**985**	**1,595**	**11,003**
Expected income tax expense at Barbados corporate tax rate of 2.5% (1.5% in 2019; 1.5% in 2018)	(25)	(24)	(165)
Over/(under) provision of prior year taxes	12	46	(71)
Non-deductible expenses	2	(10)	(474)
Income not taxable	-	48	1,897
Production sharing contract ("PSC") taxes rate differential*	(581)	(447)	(5,795)
Unused tax losses forfeited in relation to Petroleum Income tax	(906)	-	-
Utilisation of tax losses previously not recognised	22	6	-
Changes in tax rate	47	-	-
Total	**(1,429)**	**(391)**	**(4,608)**

* The PSC is calculated according to Petroleum Income tax rate of 50% (2019 and 2018: 50%) of the estimated assessable profit from Petroleum Operations in Vietnam.

The Company has cumulative tax losses of $1.7M which will expire in 2024. Losses may be carried forward for 7 years, but limited to 50% of the taxable base.

The cumulative tax losses for which deferred tax asset is not recognised is nil as of December 31, 2020 ($2,591 thousand in 2019, $3,020 thousand in 2018).

The movement of the deferred tax assets/(liabilities) of the Company are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
At 1 January	(2,785)	**(2,332)**	(1,589)
Credit/(Charge) to profit or loss			
Tax losses	42	-	-
Asset retirement obligation	(74)	853	(217)
Property, plant and equipment	283	(1,044)	(1,181)
Underlift of crude oil	(2,031)	(262)	655
At 31 December	**(4,565)**	**(2,785)**	**(2,332)**

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax relate to the same tax authority. The following amounts, determined after appropriate offsetting, are shown in the statement of financial position:

	USD'000 2020	USD'000 2019	USD'000 2018
Deferred tax assets	1,190	1,222	369
Deferred tax liabilities	(5,755)	(4,007)	(2,701)
Net deferred tax liabilities	**(4,565)**	**(2,785)**	**(2,332)**

The amounts of the deferred tax assets are mainly composed by the temporary differences generated by the asset retirement obligation and tax losses, while the amounts of deferred tax liabilities are composed by temporary differences between tax and accounting depreciation and amortization.

	USD'000 2020	USD'000 2019	USD'000 2018
Deferred tax assets:			
Tax losses	42	-	-
Asset retirement obligation	1,148	1,222	369
Total	**1,190**	**1,222**	**369**

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Deferred tax liabilities:

Underlift of crude oil	(2,674)	(643)	(381)
Property, plant and equipment	(3,081)	(3,364)	(2,320)
Total	**(5,755)**	**(4,007)**	**(2,701)**

The Company only recognizes deferred tax assets insofar as it is deemed probable that the entity will have sufficient taxable income in the future against which they can be utilized.

The amount of the deferred tax assets are composed by the temporary differences generated by the asset retirement obligation, and the amount of deferred tax liabilities is composed mainly by temporary differences between tax and accounting depreciation and amortization.

The Company was previously licensed under the International Business Companies Act Cap. 77 which has been repealed. The Company continues its licensing under the Companies Act Cap. 308. which allows provision for the same previous benefits via grandfathering under the International Business Companies (Repealed) Act, 2018-40, until the Company transitions to the new regime in 2021. The Company qualified for grandfathering. As a result, the tax rates remain at 1.0% to 2.5%.

On the repeal of the International Business Companies Act, Cap. 77., the Income Tax Act Cap. 73 was amended to apply new staggered tax rates from 1.0% to 5.5% based on the Company's income (2018 – 1.0% to 2.5%). The revised tax rates effective January 1, 2020 are as follows: taxable income up to $500 Thousand is subject to tax at 5.5%, taxable income exceeding $500 Thousand up to the next $10,000 Thousand at 3.0%, taxable income exceeding $10,000 Thousand up to $15,000 Thousand at 2.5% and all amounts in excess of $15,000 Thousand at 1.0%.

17. REVENUE AND EXPENSES

(a) Revenue

The amount of revenues is nil as of December 31, 2020 ($5,334 thousand in 2019; $15,224 thousand in 2018 – mainly proceeding from Thailand). Revenue comprises of revenue from contracts with customers of nil as of December 31, 2020 ($5,238 thousand in 2019; $11,430 thousand in 2018), and the remaining balances are crude oil delivered to Petrovietnam to settle the tax expenses.

(b) Changes in underlift

Change in underlift are broken-down as follows:

	USD'000 2020	**USD'000 2019**	**USD'000 2018**
Underlift of crude oil	3,781	1,078	(1,903)
Total	**3,781**	**1,078**	**(1,903)**

Underlift of crude oil relates to the movement of the Company's underlift position during the year and this is corresponding to the B46-CN PSC contract.

(c) Other operating expenses

Other operating expenses are broken-down as follows:

	USD'000 2020	**USD'000 2019**	**USD'000 2018**
Rental	17	18	8
Repair and maintenance	88	311	271
Processing fees	976	1,337	1,157
Training commitment*	245	245	245
Other expenses	432	387	949
Total	**1,758**	**2,298**	**2,630**

The training commitment amounted to $245 thousand is an annual commitment to be made to Petrovietnam until the end of the Company's PSC in 2027.

(d) Depletion, depreciation and amortization

Depletion, depreciation and amortization are broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Depletion, depreciation and amortization of oil and gas properties (note 9)	1,074	851	315
Amortization of intangible assets (note 8)	1	1	1
Total	**1,075**	**852**	**316**

(e) Other operating income

	USD'000 2020	USD'000 2019	USD'000 2018
Revision in estimates for ARO (Note 14)	-	-	470
Total	-	-	**470**

(f) Financial result

Financial result is broken-down as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Interest income on loan to related party (Note 12)	108	270	213
Interest income on others	-	4	3
Accretion expense	(77)	(31)	(44)
Total interest	31	**243**	**172**

Accretion expense is the unwinding of the interest of discounted long-term ARO liabilities.

	USD'000 2020	USD'000 2019	USD'000 2018
Net unrealised (loss)/gain on foreign exchange	(3)	5	3
Net realised gain/ (loss) on foreign exchange	12	(11)	(4)
Total foreign exchange gain/(loss)	**9**	**(6)**	**(1)**

18. RELATED PARTIES

18.1 Related parties' balances and transactions

Balances with related parties as at December 31, 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Amount due from related company:			
Talisman Vietnam (15-2/01) Ltd.	-	-	1,939
Due from related party	-	-	**1,939**
Loan to related company:			
Repsol International Finance B.V.	2,511	14,403	15,133
Loan to a related party	**2,511**	**14,403**	**15,133**
Amount due to related companies:			
Talisman Asia Limited - Vietnam Branch	-	-	26
Repsol Oil & Gas Malaysia Limited ("RML")	2,152	3,066	1,505
Due to related parties	**2,152**	**3,066**	**1,531**

The amounts due to/from related parties which mainly arose from non-trade transactions are unsecured, non-interest bearing and are repayable on demand. The amount owing by Talisman Vietnam (15-2/01) Ltd.in relation to development cost sharing for a project, which had been written-off during the financial year ended 31 December 2019 as the amounts were no longer recoverable.

Loan to related party is detailed in Note 12.

The material related party transactions for 2020, 2019 and 2018 are as follows:

	USD'000 2020	USD'000 2019	USD'000 2018
Loan to related party			
- TE Holdings S.A.R.L			
At January 1	-	-	5,214
Loans advanced	-	-	2,930
Loans repayment received	-	-	(1,224)
Interest charged	-	-	65
Loans transferred	-	-	(6,985)
At December 31	-	-	-
- Repsol International Finance B.V.			
At January 1	14,403	15,133	-
Loans advanced	-	5,000	11,500
Loans repayment received	(2,000)	(6,000)	(3,500)
Interest charged	108	270	148
Transfer of loan as dividend payment	(10,000)		
Loans transferred	-	-	6,985
At December 31	**2,511**	**14,403**	**15,133**
Processing fee expense to:			
- Repsol Oil & Gas Malaysia Limited ("RML")	**976**	**1,337**	**1,157**

In the normal course of business, the Company undertakes a variety of transactions with certain related companies, each of whom share a common ultimate holding company (Repsol, S.A.). These related companies include Talisman Vietnam (15-2/01) Ltd., Repsol International Finance B.V., Talisman Asia Limited - Vietnam Branch, RML and TE Holdings S.A.R.L.

As disclosed in Note 10, RML was appointed as to be the unit operator to conduct the operations of East Bunga Kekwa-Cai Nuoc Unit Area. As a result, processing fees were charged by RML to the Company for the services performed.

18.2 Information referring to the Directors

Remuneration and other benefits paid to the Directors

In 2020, the Company has paid $10.8 thousand to its Directors for attending to the functions inherent to the Company management ($12.2 thousand in 2019; $12.2 thousand in 2018).

At December 31, 2020 the Company had not assumed any obligations regarding pensions or life insurance for its Directors, nor were any advances, loans or credits made to them by the Company.

19. PRODUCTION SHARING CONTRACT

The Company secures the rights to carry out exploration activities in the international block through a Production Sharing Contract ("PSC") arrangement with the national oil company which is Petrovietnam. Detailed information on B46-CN PSC is disclosed in Notes 1 and 10.

The Company recognises the cost of dismantling and removing the assets and restoring the site on which they are located when there is an obligation to do so.

20. EVENTS SUBSEQUENT TO YEAR END

Since the end of 2020, there have been no significant events..

Effective June 30, 2021 the benefits under the International Business Companies Act (Repealed) Act 2018-40 will expire. The company will be required to comply with the Companies (Economic Substance) Act, 2019-43 (CESA) with effect from January 1, 2021. The Act imposes an economic substance test on Barbados-resident companies that are managed and controlled in Barbados or Incorporated/registered in Barbados and not considered a tax resident in another jurisdiction. The Act also requires that the companies conduct relevant activities as defined under the Act. The Company is in compliance with the new Act based on the management's assessment.

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21. OTHER INFORMATION

21.1 Contingent liabilities

At December 31, 2020, December 31, 2019 and December 31, 2018 the Company had not assumed any tax or legal contingent liabilities.

pwc

The Board of Directors
Hibiscus Petroleum Berhad
2nd floor,
Syed Kechik Foundation Building,
Jalan Kapas, Bangsar,
59100 Kuala Lumpur.

4 October 2021

PwC/TEH/TGL/sw/0900B1

Dear Sirs,

Report on the Compilation of Pro Forma Consolidated Statement of Financial Position

1 We have completed our assurance engagement to report on the compilation of the Pro Forma Consolidated Statement of Financial Position of Hibiscus Petroleum Berhad (the "Company") as at 30 June 2021 (the "Pro Forma Consolidated Statement of Financial Position"). The Pro Forma Consolidated Statement of Financial Position which we have stamped for the purpose of identification, has been compiled by the Directors of the Company (the "Directors") for inclusion in the circular to shareholders (the "Circular to Shareholders") to be dated 4 October 2021 in connection with the proposed acquisition of Fortuna International Petroleum Corporation and its subsidiaries ("Fortuna Group") by the Company (the "Proposal").

2 The applicable criteria on the basis of which the Directors have compiled the Pro Forma Consolidated Statement of Financial Position are described in the notes thereon to the Pro Forma Consolidated Statement of Financial Position.

3 The Pro Forma Consolidated Statement of Financial Position has been compiled by the Directors, for illustrative purposes only, to show the effects of the events or transactions as set out in the notes thereon to the Pro Forma Consolidated Statement of Financial Position on the Company's consolidated statement of financial position as at 30 June 2021 had the events or transactions been effected on that date. As part of this process, information about the Company's consolidated financial position has been extracted by the Directors from the Company's consolidated financial statements for the financial year ended 30 June 2021, on which an audit report has been published.

The Directors' Responsibility for the Pro Forma Consolidated Statement of Financial Position

4 The Directors are responsible for compiling the Pro Forma Consolidated Statement of Financial Position on the basis set out in the notes thereon to the Pro Forma Consolidated Statement of Financial Position and in accordance with the Malaysian Institute of Accountants' Guidance Note for Issuers of Pro Forma Financial Information.

PricewaterhouseCoopers PLT (LLP0014401-LCA & AF 1146), Chartered Accountants, Level 10, 1 Sentral, Jalan Rakyat, Kuala Lumpur Sentral, P.O. Box 10192, 50706 Kuala Lumpur, Malaysia
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pwc

The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/TGL/sw/0900B1
4 October 2021

Our Independence and Quality Control

5 We have complied with the independence and other ethical requirement of the By-Laws (on Professional Ethics, Conduct and Practice) of the Malaysian Institute of Accountants and the International Ethics Standards Board for Accountants' International Code of Ethics for Professional Accountants (including International Independence Standards), which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

6 Our firm applies the International Standard on Quality Control 1 and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Reporting Accountants' Responsibilities

7 Our responsibility is to express an opinion, about whether the Pro Forma Consolidated Statement of Financial Position has been compiled, in all material respects, by the Directors on the basis set out in the notes thereon to the Pro Forma Consolidated Statement of Financial Position and in accordance with the Malaysian Institute of Accountants' Guidance Note for Issuers of Pro Forma Financial Information.

8 We conducted our engagement in accordance with International Standard on Assurance Engagements 3420 "Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus" ("ISAE 3420"), issued by the Malaysian Institute of Accountants. This standard requires that we plan and perform procedures to obtain reasonable assurance about whether the Directors have compiled, in all material respects, the Pro Forma Consolidated Statement of Financial Position on the basis set out in the notes thereon to the Pro Forma Consolidated Statement of Financial Position and in accordance with the Malaysian Institute of Accountants' Guidance Note for Issuers of Pro Forma Financial Information.

9 For purposes of this engagement, we are not responsible for updating or reissuing any reports or opinions on any historical financial information used in compiling the Pro Forma Consolidated Statement of Financial Position, nor have we, in the course of this engagement, performed an audit or review of the financial information used in compiling the Pro Forma Consolidated Statement of Financial Position. In providing this opinion, we do not accept any responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

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The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/TGL/sw/0900B1
4 October 2021

Reporting Accountants' Responsibilities (continued)

10 The purpose of the Pro Forma Consolidated Statement of Financial Position included in the Circular to Shareholders is solely to illustrate the impact of significant events or transactions on unadjusted financial information of the Company as if the events had occurred or the transactions had been undertaken at an earlier date selected for purposes of the illustration. Accordingly, we do not provide any assurance that the actual outcome of the events or transactions at that date would have been as presented.

11 A reasonable assurance engagement to report on whether the Pro Forma Consolidated Statement of Financial Position has been compiled, in all material respects, on the basis of the applicable criteria, involves performing procedures to assess whether the applicable criteria as disclosed in the notes thereon to the Pro Forma Consolidated Statement of Financial Position provides a reasonable basis for presenting the significant effects directly attributable to the events or transactions, and to obtain sufficient appropriate evidence about whether:

- The related pro forma adjustments give appropriate effect to those criteria; and
- The Pro Forma Consolidated Statement of Financial Position reflects the proper application of those adjustments to the unadjusted financial information.

12 The procedures selected depend on our judgment, having regard to our understanding of the nature of the Company, the events or transactions in respect of which the Pro Forma Consolidated Statement of Financial Position has been compiled, and other relevant engagement circumstances. The engagement also involves evaluating the overall presentation of the Pro Forma Consolidated Statement of Financial Position.

13 We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Our Opinion

14 In our opinion, the Pro Forma Consolidated Statement of Financial Position has been compiled, in all material respects, on the basis set out in the notes thereon to the Pro Forma Consolidated Statement of Financial Position and in accordance with Malaysian Institute of Accountants' Guidance Note for Issuers of Pro Forma Financial Information.

The Board of Directors
Hibiscus Petroleum Berhad
PwC/TEH/TGL/sw/0900B1
4 October 2021

Restriction on Distribution and Use

15 This report is issued for the sole purpose of inclusion in the Circular to Shareholders in connection with the Proposal and should not be used or relied upon for any other purpose. Accordingly, we will not accept any liability or responsibility to any other party to whom our report is shown or into whose hands it may come.

Yours faithfully,

PricewaterhouseCoopers PLT
LLP0014401-LCA & AF 1146
Chartered Accountants

HIBISCUS PETROLEUM BERHAD

PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021

The Pro Forma Consolidated Statement of Financial Position as set out below has been prepared by the Directors of Hibiscus Petroleum Berhad ("Hibiscus Petroleum", "HPB" or "the Company") for illustrative purposes only to show the effects on the audited Consolidated Statement of Financial Position of HPB and its subsidiaries ("HPB Group or "the Group") as at 30 June 2021 on the assumption that the Proposed Acquisition as set out in Note 2 had been effected on that date, and should be read in conjunction with the notes thereon.

	As at 30 June 2021 RM'000	Proforma – After the Proposed Acquisition RM'000
ASSETS		
NON-CURRENT ASSETS		
Intangible assets	1,375,808	1,386,074
Equipment	604,833	2,010,482
Right-of-use assets	12,407	113,314
Other receivables	5,458	5,458
Investment in an associate	4,381	4,381
Restricted cash and bank balances	125,581	125,581
Tax recoverable	-	47,491
Deferred tax assets	-	123,493
	2,128,468	3,816,274
CURRENT ASSETS		
Inventories	49,462	148,441
Trade receivables	112,905	381,728
Other receivables, deposits and prepayments	182,808	120,605
Other investment	136,430	136,430
Amount owing by a joint venture	318	318
Cash and bank balances	177,652	-
Tax recoverable	-	12,077
	659,575	799,599
TOTAL ASSETS	2,788,043	4,615,873

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PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION OF THE COMPANY AS AT 30 JUNE 2021 TOGETHER WITH THE REPORTING ACCOUNTANT'S REPORT (CONT'D)

HIBISCUS PETROLEUM BERHAD

PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021 (CONTINUED)

The Pro Forma Consolidated Statement of Financial Position as set out below has been prepared by the Directors of Hibiscus Petroleum Berhad ("Hibiscus Petroleum", "HPB" or "the Company") for illustrative purposes only to show the effects on the audited Consolidated Statement of Financial Position of HPB and its subsidiaries ("HPB Group or "the Group") as at 30 June 2021 on the assumption that the Proposed Acquisition as set out in Note 2 had been effected on that date, and should be read in conjunction with the notes thereon. (continued)

	As at 30 June 2021 RM'000	Proforma – After the Proposed Acquisition RM'000
EQUITY AND LIABILITIES		
EQUITY		
Share capital	959,892	959,892
Other reserves	62,165	62,165
Retained earnings	451,865	480,583
	1,473,922	1,502,640
NON-CURRENT LIABILITIES		
Other payables	9,545	19,263
Borrowings	11,230	175,254
Convertible Redeemable Preference Shares – Liability Component	5,677	5,677
Contingent consideration	19,683	19,683
Deferred tax liabilities	471,958	492,382
Provision for decommissioning costs	322,697	681,528
	840,790	1,393,787
CURRENT LIABILITIES		
Trade payables	9,638	300,159
Other payables and accruals	293,072	751,402
Borrowings	15,540	15,540
Amount owing to a joint venture	318	318
Amount owing to an associate	119	119
Contingent consideration	25,251	25,251
Provision for decommissioning costs	58,677	150,764
Provision for taxation	70,497	475,674
Redeemable Convertible Preference Shares	219	219
	473,331	1,719,446
TOTAL LIABILITIES	1,314,121	3,113,233
TOTAL EQUITY AND LIABILITIES	2,788,043	4,615,873

HIBISCUS PETROLEUM BERHAD
NOTES TO THE PROFORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021

1 INTRODUCTION

The Pro Forma Consolidated Statement of Financial Position ("Pro Forma Consolidated SOFP") of HPB Group for which the Directors of the Company are solely responsible, has been prepared for illustrative purposes only, for the purpose of inclusion in the Circular to Shareholders in connection with the proposed acquisition of the entire equity interest in Fortuna International Petroleum Corporation ("FIPC") by Peninsula Hibiscus Sdn Bhd ("Peninsula Hibiscus"), an indirect wholly owned subsidiary of HPB, as set out in Note 2 ("the Proposed Acquisition").

The Pro Forma Consolidated SOFP has been prepared in accordance with the MIA Guidance Note for Issuers of Pro Forma Financial Information, for illustrative purposes only to show the effects of the Proposed Acquisition on the audited consolidated SOFP of HPB Group as at 30 June 2021, had the Proposed Acquisition been effected on 30 June 2021 ("Assumed Acquisition Date").

As the Pro Forma Consolidated SOFP has been prepared for illustrative purposes only, such information, because of its hypothetical nature, does not give a true picture of the effects of the Proposed Acquisition on the financial position of HPB Group presented had the Proposed Acquisition occurred on 30 June 2021. Further, such information does not purport to predict HPB Group's future financial position.

2 PROPOSED ACQUISITION

2.1 Proposed acquisition of the entire equity interest in Fortuna International Petroleum Corporation

Peninsula Hibiscus ("the Purchaser") has on 1 June 2021 entered into a conditional sale and purchase agreement ("SPA") with Repsol Exploración, S.A. ("Repsol" or "the Seller") for the proposed acquisition by Peninsula Hibiscus of the entire equity interest in FIPC ("FIPC Shares") for a cash consideration of USD212.5 million.

The Proposed Acquisition entails the acquisition by Peninsula Hibiscus of the entire equity interest in FIPC, subject to the terms and conditions of the SPA.

FIPC through its wholly-owned subsidiaries, namely Repsol Oil & Gas Malaysia Limited ("RML"), Repsol Oil & Gas Malaysia (PM3) Limited ("RMPM3") and Talisman Vietnam Limited ("TVL") (collectively, "FIPC Group") owns participating interests in the following production sharing contracts ("PSC"):

(i) 60% interest in the 2012 Kinabalu Oil PSC located off the coast of Sabah, Malaysia ("2012 Kinabalu Oil"), currently held by RML;
(ii) 35% interest in the PM3 CAA PSC located within the Commercial Arrangement Area ("CAA") between Malaysia and Vietnam ("PM3 CAA"), currently held by RMPM3 (12.7%) and RML (22.3%);
(iii) 60% interest in each of the PM305 and PM314 PSCs located off the eastern coast of Peninsular Malaysia in the Malay Basin ("PM305 and PM314"), currently held by RML; and
(iv) 70% interest in the Block 46 PSC (Cai Nuoc), a tie-back asset to the PM3 CAA PSC located in Vietnamese waters ("Block 46"), currently held by TVL.

(The 2012 Kinabalu Oil, PM3 CAA, PM305, PM314 and Block 46 are collectively referred to as the "Assets").

HIBISCUS PETROLEUM BERHAD
NOTES TO THE PROFORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021 (CONTINUED)

2 PROPOSED ACQUISITION (CONTINUED)

2.2 The purchase price

The purchase price of USD212.5 million ("Purchase Price") under the SPA, takes into account a base purchase price and a working capital adjustment of the FIPC Group as at 31 December 2020 and is subject to adjustments to be calculated in accordance with the SPA.

The agreed adjustments to the Purchase Price are as follows:

(i) (plus) Time value amount: generally, an amount equal to three percent (3%) per annum accruing daily and compounding monthly on the balance of the base purchase price less the Deposits (as defined below), calculated for the period from, and including the Effective Date (defined as 1 January 2021) to, and including, the date of completion of the SPA ("Closing Date");

(ii) (less) Pre-closing dividend: the contemplated dividend/distribution payment from FIPC to Repsol based on cash balances available in the FIPC Group, subject to the agreement of the Purchaser, prior to completion of the SPA; and

(iii) (less) Leakage adjustment amount (estimated, if any): the amount of estimated Seller-related payouts (being any relevant payment/matter to, or on behalf of, or for the benefit of the Seller or any member of Seller Group for the period from and including the Effective Date to and including the day immediately prior to the Closing Date, subject to the agreement of the Purchaser.

Peninsula Hibiscus has paid a partial deposit of USD7.5 million to Repsol upon the execution of the SPA. The balance deposit of USD7.5 million has also been paid to Repsol following the receipt of the approval from Bank Negara Malaysia for the Proposed Acquisition on 21 June 2021 (the total monies paid towards the above deposit being collectively referred to as "Deposits"). The balance of the Purchase Price after the several adjustments ("Final Price") shall be paid by Peninsula Hibiscus on Closing Date.

The funding of the Purchase Price will include a combination of the following:

(i) The remaining net proceeds raised from the placement of the first and second tranche of the private placement of Islamic Convertible Redeemable Preference Shares ("CRPS") of about RM136.9 million as at 31 August 2021 (after taking account the payment of Deposits of USD15.0 million (or RM61.8 million, based on actual RM equivalent) in the custodian account);

(ii) debt/borrowings;

(iii) funds available in the FIPC Group at Closing;

(iv) internally generated funds of HPB Group; and/or

(v) potential funds to be raised from subsequent tranche(s) of the private placement of CRPS.

The actual breakdown of the source of funding will only be determined later and will depend on, amongst others, HPB Group's cash reserves and future funding requirements.

HIBISCUS PETROLEUM BERHAD
NOTES TO THE PROFORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021 (CONTINUED)

3 BASIS OF PREPARATION

3.1 The Pro Forma Consolidated SOFP, for which the Directors of the Company are solely responsible, has been prepared based on the audited consolidated financial statements of HPB for the financial year ended 30 June 2021 in accordance with Malaysian Financial Reporting Standards ("MFRS"), International Financial Reporting Standards ("IFRS"), and in a manner consistent with both the format of the financial statements and the accounting policies adopted by the Group for the financial year then ended.

4 EFFECTS ON THE PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION

The Pro Forma Consolidated SOFP have been prepared for illustrative purposes only to show the effects of the Proposed Acquisition as set out in Note 2.

4.1 Effects of Proposed Acquisition

The Pro Forma Consolidated SOFP incorporates the effects of the completion of the Proposed Acquisition, being fulfilment of all conditions precedent set out in the SPA. For purposes of illustration in the Pro Forma Consolidated SOFP, the Proposed Acquisition has been accounted for as an acquisition of a business.

For purposes of illustration in the Pro Forma Consolidated SOFP, the Assumed Acquisition Date is 30 June 2021 and the purchase consideration is assumed to be USD212.5 million (equivalent to RM882.9 million based on USD1:RM4.1546). The purchase consideration is assumed settled as follows:

	Amount (USD million)	Amount (RM million)*	Notes
Deposits paid by the Company recognised under Other Receivables, Deposits and Prepayments (current) as at the Assumed Acquisition Date	15.0	62.3	5.2
Available cash at the Assumed Acquisition Date in the Pro Forma Consolidated SOFP	89.1	370.3	5.1
Balance of the purchase consideration illustrated as Other Payables and Accruals (current) at the Assumed Acquisition Date in the Pro Forma Consolidated SOFP	108.4	450.3	5.3
Total	**212.5**	**882.9**	

* based on USD1: RM4.1546

4 EFFECTS ON THE PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION (CONTINUED)

The Pro Forma Consolidated SOFP have been prepared for illustrative purposes only to show the effects of the Proposed Acquisition as set out in Note 2.

4.1 Effects of Proposed Acquisition (continued)

Assets acquired and liabilities assumed

The provisional fair value of the identifiable assets and liabilities of FIPC and its subsidiaries as at the Assumed Acquisition Date is as follows:

	Provisional fair value on acquisition RM'000
Non-current assets	
Intangible assets	10,266
Equipment	1,405,649
Right-of-use assets	100,907
Tax recoverable	47,491
Deferred tax assets	123,493
Current assets	
Inventories	98,979
Trade receivables	268,823
Other receivables, deposits and prepayments	116
Cash and bank balances	192,628
Tax recoverable	12,077
Non-current liabilities	
Other payables	(9,718)
Borrowings	(164,024)
Deferred tax liabilities	(20,424)
Provision for decommissioning costs	(358,831)
Current liabilities	
Trade payables	(290,521)
Other payables and accruals	(1,004)
Provision for decommissioning costs	(92,087)
Provision for taxation	(405,177)
Total identifiable assets and liabilities at fair value	918,643
Provisional negative goodwill arising from acquisition	(35,790)
Purchase consideration	882,853

4 EFFECTS ON THE PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION (CONTINUED)

4.1 Effects of Proposed Acquisition (continued)

Assets acquired and liabilities assumed (continued)

The fair value of the oil and gas reserves, included as part of Equipment, is based on the Company's preliminary valuation. The fair value of other identifiable assets and liabilities are assumed to approximate the carrying amount of the assets and liabilities shown in the audited financial statements of FIPC and its subsidiaries as at 31 December 2020 after adjustments to align to the accounting policies of the Group. The respective financial statements of FIPC, RML, RMPM3 and TVL for the financial year ended 31 December 2020 which are prepared in accordance with MFRS and IFRS as contained in the respective Accountants' Reports of FIPC RML, RMPM3 and TVL are audited by PricewaterhouseCoopers PLT, Malaysia and are not subject to any qualification or modification.

The difference between the fair value of the purchase consideration and fair value of the identifiable assets and liabilities is recognised as negative goodwill.

The exercise to allocate the purchase consideration to the assets acquired and liabilities assumed will be performed at a later stage and hence the identification and measurement of the various components of business combination could be materially different from the amounts shown in the Pro Forma Consolidated SOFP.

Acquisition-related costs

Transactions costs incurred in relation to the Proposed Acquisition estimated at RM7.1 million have been charged to profit or loss. The transaction costs are assumed to be payable in the Pro Forma Consolidated SOFP.

5 NOTES TO THE EFFECTS ON THE PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION

5.1 Cash and bank balances

	RM'000
As at 30 June 2021	**177,652**
Cash and bank balances from FIPC and its subsidiaries	192,628
Partial payment of purchase consideration	(370,280)
As per Pro Forma Consolidated SOFP	-

HIBISCUS PETROLEUM BERHAD
NOTES TO THE PROFORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION AS AT 30 JUNE 2021 (CONTINUED)

5 NOTES TO THE EFFECTS ON THE PRO FORMA CONSOLIDATED STATEMENT OF FINANCIAL POSITION

5.2 Other receivables, deposits and prepayments (current)

	RM'000
As at 30 June 2021	**182,808**
Other receivables, deposits and prepayments balances from FIPC and its subsidiaries	116
Reversal of Deposits paid upon assumed completion of the Proposed Acquisition	(62,319)
As per Pro Forma Consolidated SOFP	**120,605**

5.3 Other payables and accruals (current)

	RM'000
As at 30 June 2021	**293,072**
Liabilities assumed from FIPC and its subsidiaries	1,004
Purchase consideration illustrated as Other Payables and Accruals at the Assumed Acquisition Date	450,254
Acquisition related costs	7,072
As per Pro Forma Consolidated SOFP	**751,402**

5.4 Retained earnings

	RM'000
As at 30 June 2021	**451,865**
Acquisition related costs	(7,072)
Provisional negative goodwill	35,790
As per Pro Forma Consolidated SOFP	**480,583**

APPROVAL BY BOARD OF DIRECTORS

Approved and signed on behalf of the Board of Directors of Hibiscus Petroleum Berhad on 4 October 2021.

DR KENNETH GERARD PEREIRA
MANAGING DIRECTOR

ADDITIONAL INFORMATION

1. DIRECTORS' RESPONSIBILITY STATEMENT

Our Directors have seen and approved this Circular and they collectively and individually accept full responsibility for the accuracy of the information given in this Circular. They confirm that after making all reasonable enquiries and to the best of their knowledge and belief, there are no false or misleading statements or other facts, the omission of which would make any statement in this Circular misleading.

The information on the Seller, the FIPC Group and the Assets was obtained from the Seller or based on public and other available information, and the responsibility of our Board is limited to ensuring that this information is correctly extracted and reproduced in this Circular.

2. CONSENTS AND CONFLICTS OF INTEREST

2.1 CIMB

CIMB, being our Principal Adviser for the Proposed Acquisition, has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name and all references thereto, in the form and context in which they appear.

CIMB, its related and associated companies, as well as its holding company, CIMB Group Holdings Berhad and the subsidiaries and associated companies of its holding company (the "**CIMB Group**") form a diversified financial group and are engaged in a wide range of investment and commercial banking, brokerage, securities trading, asset and funds management and credit transaction service businesses. The CIMB Group has engaged and may in the future, engage in transactions with and perform services for our Company and/or our affiliates, in addition to the role as Principal Adviser for the Proposed Acquisition. In addition, in the ordinary course of business, any member of the CIMB Group may at any time offer or provide its services to or engage in any transactions (on its own account or otherwise) with our Company and/or our affiliates and/or any other entity or person, hold long or short positions in securities issued by our Company and/or our affiliates, make investment recommendations and/or publish or express independent research views on such securities, and may trade or otherwise effect transactions for its own account or the account of its customers in debt or equity securities or senior loans of our Company and/or our affiliates. This is a result of the businesses of the CIMB Group generally acting independently of each other, and accordingly there may be situations where parts of the CIMB Group and/or its customers now have or in the future, may have interest in or take actions that may conflict with the interests of our Company and/or our affiliates.

CIMB confirms that it is not aware of any conflict of interest that exists or is likely to exist in relation to its role as the Principal Adviser to our Company for the Proposed Acquisition.

2.2 RPS Energy

RPS Energy has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the Competent Valuer's Report, the expert reports on the fairness of the Purchase Price for the Assets and the Competent Person's Report and all references thereto, in the form and context in which they appear.

RPS Energy confirms that, it is also not aware of any possible conflict of interest which exists or is likely to exist in its capacities as the independent valuer in respect of the Assets, as the expert providing the Competent Valuer's Report, the expert reports on the fairness of the Purchase Price for the Assets and the Competent Person's Report.

ADDITIONAL INFORMATION (CONT'D)

2.3 PricewaterhouseCoopers Taxation Services Sdn Bhd ("PwC Tax")

PwC Tax has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, letter of policies on foreign investments, repatriation of profits, taxation and anti-avoidance in Barbados and all references thereto, in the form and context in which they appear.

PwC Tax confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as the expert providing the letter of policies on foreign investments, repatriation of profits, taxation and anti-avoidance in Barbados.

2.4 Hamel-Smith Caribbean ("HSC")

HSC has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, legal opinion on the ownership of title to the shares of FIPC and all references thereto, in the form and context in which they appear.

HSC confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our foreign legal counsel in providing the legal opinion on the ownership of title to the shares of FIPC under the laws of Barbados.

2.5 Herbert Smith Freehills Spain LLP ("HSF SPAIN")

HSF SPAIN has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of Spain, and all references thereto, in the form and context in which they appear.

HSF SPAIN confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our foreign legal counsel in providing the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of Spain.

2.6 Herbert Smith Freehills LLP ("HSF")

HSF has given and has not subsequently withdrawn its written consent to the inclusion in this Circular of its name, the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of England and Wales, and all references thereto in the form and context in which they appear.

HSF confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our foreign legal counsel in providing the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of England and Wales.

2.7 PricewaterhouseCoopers PLT ("PwC PLT")

PwC PLT, confirm that it has given and have not subsequently withdrawn its written consent to the inclusion in this Circular of its name, its opinions on the historical financial statements for the FYE 31 December 2018, 2019 and 2020 included in the accountant's reports of FIPC, RML, RMPM3 and TVL, its report on the pro forma consolidated statement of financial position of our Company as at 30 June 2021 together with the Reporting Accountant's report and all references thereto, in the form and context which they appear in the Circular.

PwC PLT confirms that, it is not aware of any possible conflict of interest which exists or is likely to exist in its capacity as our reporting accountants for the Proposed Acquisition.

ADDITIONAL INFORMATION (CONT'D)

3. MATERIAL COMMITMENTS

Save as disclosed below, as at 30 September 2021, being the date of the latest unaudited quarterly report of our Group, our Group does not have any other material commitments incurred or known to be incurred by our Group which, upon becoming enforceable, may have a material impact on the financial position of our Group:

	RM'000
Approved and contracted for:	
▪ Group's capital commitments	21,930
▪ Share of a joint operation's capital commitments	7,819
Total capital commitments approved and contracted for	29,749
Share of a joint operation's other material commitments	33,605
	63,354
Approved but not contracted for:	
▪ Group's capital commitments	9,341
▪ Share of a joint operation's capital commitments	2,491
Total capital commitments approved but not contracted for	11,832
Share of a joint operation's other material commitments	3,264
	15,096

4. CONTINGENT LIABILITIES

As at 30 September 2021, being the date of the latest unaudited quarterly report of our Group, there are no contingent liabilities incurred or known to be incurred by our Group which, upon becoming enforceable, may have a material impact on the financial position of our Group.

5. DOCUMENTS AVAILABLE FOR INSPECTION

The following documents or copies of them are available for inspection during normal business hours at the registered office of our Company at 12th Floor, Menara Symphony, No. 5, Jalan Prof. Khoo Kay Kim, Seksyen 13, 46200 Petaling Jaya, Selangor Darul Ehsan, Malaysia, from Mondays to Fridays (except public holidays) from the date of this Circular up to the time stipulated for the holding of the EGM:

(i) our constitution and the constitution (or such corresponding document under its country of incorporation) of FIPC;

(ii) our audited consolidated financial statements for the FYE 30 June 2020 and the FYE 30 June 2021;

(iii) the SPA;

(iv) the Parent Company Guarantee;

(v) the Transition Services Agreement;

(vi) the Competent Valuer's Report as set out in Appendix V of this Circular;

(vii) the expert's report on the fairness of the Purchase Price as set out in Appendix VI of this Circular;

ADDITIONAL INFORMATION (CONT'D)

(viii) the Competent Person's Report in relation to the Reserves and resources evaluation on the Assets as set out in Appendix VII of this Circular;

(ix) the letter of policies on foreign investments, repatriation of profits, taxation and anti-avoidance in Barbados as set out in Appendix VIII of this Circular;

(x) the legal opinion on the ownership of title to the shares of FIPC under the laws of Barbados as set out in Appendix IX of this Circular;

(xi) the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of Spain as set out in Appendix X of this Circular;

(xii) the legal opinion on the enforceability of agreements, representations and undertakings given by the Seller under the laws of England and Wales as set out in Appendix XI of this Circular;

(xiii) Directors' report on FIPC as set out in Appendix XII of this Circular;

(xiv) Accountant's report on FIPC as set out in Appendix XIII of this Circular;

(xv) Accountant's report on RML as set out in Appendix XIV of this Circular;

(xvi) Accountant's report on RMPM3 as set out in Appendix XV of this Circular;

(xvii) Accountant's report on TVL as set out in Appendix XVI of this Circular;

(xviii) Pro forma consolidated statement of financial position of the Company as at 30 June 2021 together with the Reporting Accountant's report as set out in Appendix XVII of this Circular;

(xix) the audited financial statements of FIPC and each of its subsidiaries, namely RML, RMPM3 and TVL for the FYE 31 December 2019 and the FYE 31 December 2020 and the unaudited interim financial statements of FIPC, RML, RMPM3 and TVL as at and for the six months FPE 30 June 2021, prepared in accordance with MFRS and IFRS;

(xx) the letters of consent referred to in Section 2 of this Appendix XVIII; and

(xxi) the relevant cause papers in respect of material litigation as set out in Section 10 of Appendix III of this Circular.

HIBISCUS PETROLEUM BERHAD
Registration Number: 200701040290 (798322-P)
(Incorporated in Malaysia)

NOTICE OF EXTRAORDINARY GENERAL MEETING

NOTICE IS HEREBY GIVEN THAT an Extraordinary General Meeting ("**EGM**") of Hibiscus Petroleum Berhad ("**Hibiscus Petroleum**" or "**Company**") will be held via a virtual platform at the broadcast venue at Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia ("**Broadcast Venue**") on Tuesday, 28 December 2021 at 9.30 a.m. or at any adjournment thereof, for the purpose of considering and if thought fit, to pass the following resolution (with or without modifications):

ORDINARY RESOLUTION

PROPOSED ACQUISITION BY PENINSULA HIBISCUS SDN BHD ("PENINSULA HIBISCUS"), AN INDIRECT WHOLLY-OWNED SUBSIDIARY OF HIBISCUS PETROLEUM BERHAD ("HIBISCUS PETROLEUM"), OF THE ENTIRE ISSUED SHARE CAPITAL OF FORTUNA INTERNATIONAL PETROLEUM CORPORATION ("FIPC") FOR A CASH CONSIDERATION OF USD212.5 MILLION (OR EQUIVALENT TO APPROXIMATELY RM879.5 MILLION) ("PROPOSED ACQUISITION")

"**THAT**, subject to the approvals of all relevant regulatory authorities being obtained upon terms and/or conditions acceptable to the Company's Board of Directors, approval be and is hereby given for Peninsula Hibiscus, an indirect wholly-owned subsidiary of Hibiscus Petroleum, to acquire the entire issued share capital of FIPC for a cash consideration of USD212.5 million (or equivalent to approximately RM879.5 million), subject to adjustments, pursuant to and in accordance with the terms of the Sale and Purchase Agreement dated 1 June 2021 in relation to the Proposed Acquisition, as further elaborated in the Company's circular to shareholders dated 13 December 2021.

AND THAT the Directors of the Company, be and are hereby empowered and authorised to do all acts, deeds and things and to execute, sign, deliver and cause to be delivered on behalf of the Company all such documents and/or agreements (including, without limitation, the affixing of the Company's common seal, where necessary) as the Directors may consider necessary, expedient or relevant to give effect to and complete the Proposed Acquisition and with full power to assent to any conditions, terms, modifications, variations and/or amendments in any manner as may be required by the relevant authorities or as the Directors may deem necessary, expedient or relevant in the best interest of the Company and to take such steps as they may deem necessary, expedient or relevant in order to implement, finalise and give full effect to the Proposed Acquisition."

BY ORDER OF THE BOARD

Tai Yit Chan (MAICSA 7009143) (SSM PC No. 202008001023)
Tan Ai Ning (MAICSA 7015852) (SSM PC No. 202008000067)
Secretaries

Selangor Darul Ehsan
13 December 2021

Notes:

1. *In light of the Coronavirus ("**COVID-19**") pandemic and in line with the Guidance and Frequently Asked Questions ("**FAQs**") on the Conduct of General Meetings for Listed Issuers issued by the Securities Commission Malaysia, the EGM of the Company will be conducted entirely on a virtual basis through live streaming and online remote voting via Remote Participation and Voting ("**RPV**") facilities. The Company has appointed Tricor Investor & Issuing House Services Sdn Bhd ("**TIIH**") as the Poll Administrator for this EGM to facilitate the RPV via TIIH Online website at https://tiih.online. The procedures for members to register, participate and vote remotely via the RPV facilities are provided in the Administrative Guide for this EGM.*

2. *The Broadcast Venue is strictly for the purpose of complying with Section 327(2) of the Companies Act, 2016, which requires the Chair of the meeting to be present at the main venue. Members/proxies **are NOT** to be physically present at the Broadcast Venue on the day of this EGM.*

3. *For purposes of determining who shall be entitled to attend this EGM in accordance with Clauses 72(b) and 72(c) of the Company's Constitution and Section 34(1) of the Securities Industry (Central Depositories) Act, 1991, the Company shall be requesting Bursa Malaysia Depository Sdn Bhd to issue a General Meeting Record of Depositors as at 21 December 2021 and only Depositors whose name appear on such Record of Depositors shall be entitled to attend, speak (in the form of real time submission of typed texts) and vote via RPV at this EGM.*

4. *A member shall be entitled to appoint up to two (2) proxies to attend and vote at the EGM via RPV. Where a member appoints more than one (1) proxy, the appointments shall be invalid unless he specifies the proportions of his holdings to be represented by each proxy. A proxy appointed to attend and vote at the EGM via RPV shall have the same right as a member to speak (in the form of real time submission of typed texts) at the EGM.*

5. *A proxy or attorney or a duly authorised representative may, but need not be a member of the Company. There shall be no restriction as to the qualification of the proxy.*

6. *Where a member is an authorised nominee as defined under the Securities Industry (Central Depositories) Act, 1991 which is exempted from compliance with the provisions of subsection 25A(1) of the Securities Industry (Central Depositories) Act, 1991 (Exempt Authorised Nominee) which holds Ordinary Shares in the Company for multiple beneficial owners in one (1) securities account (Omnibus Account), there is no limit to the number of proxies which the Exempt Authorised Nominee may appoint in respect of each Omnibus Account it holds. Where the Exempt Authorised Nominee appoints more than one (1) proxy, the proportion of shareholdings to be represented by each proxy must be specified in the instrument appointing the proxies.*

7. *A member who has appointed a proxy or attorney or authorised representative to attend and vote at this EGM via RPV must request his/her proxy to register himself/herself for RPV at TIIH Online website at https://tiih.online.*

   Please follow the procedures for RPV set out in the Administrative Guide.

8. *For members who wish to appoint a proxy, the appointment of a proxy may be made in hard copy form or by electronic means.*

Proxy Forms must be submitted in the following manner, not less than forty-eight (48) hours before the time appointed for holding the EGM or adjourned meeting provided that in the event the member(s) duly executes the Form of Proxy but does not name any proxy, such member(s) shall be deemed to have appointed the Chair of the meeting as his/their proxy, provided always that the rest of the Form of Proxy, other than the particulars of the proxy has been duly completed by the member(s):

(i) In hard copy form

(a) To be valid, the Form of Proxy duly completed must be deposited at the Company's Share Registrar, Tricor Investor & Issuing House Services Sdn Bhd's address at Unit 32-01, Level 32, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur or its Customer Service Centre at Unit G-3, Ground Floor, Vertical Podium, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur.

(b) If the Form of Proxy is signed under the hands of an appointor or his attorney duly authorised (or if the appointor is a corporation, the Form of Proxy must be executed under its common seal or under the hands of an officer or attorney duly authorised), it should be accompanied by a statement reading "signed as authorised officer under Authorisation Document which is still in force, no notice of revocation having been received". If the Form of Proxy is signed under the attorney duly appointed under a power of attorney, it should be accompanied by a statement reading "signed under Power of Attorney which is still in force, no notice of revocation having been received". A copy of the Authorisation Document or the Power of Attorney, which should be valid in accordance with the laws of the jurisdiction in which it was created and is exercised, should be enclosed in the Form of Proxy.

(ii) Via Tricor Online System (TIIH Online)

The Proxy Form can be electronically submitted via TIIH Online at https://tiih.online. Please follow the procedures set out in the Administrative Guide.

9. Pursuant to Paragraph 8.29A of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad, the resolution set out in the Notice of this EGM will be put to vote by way of poll. An Independent Scrutineer will be appointed to verify the poll results.

PERSONAL DATA POLICY

By submitting an instrument appointing a proxy(ies) and/or representative(s) to attend, speak (in the form of real time submission of typed texts) and vote at the EGM and/or any adjournment thereof, a member of the Company (i) consents to the collection, use and disclosure of the member's personal data by the Company (or its agents) for the purpose of the processing and administration by the Company (or its agents) of proxies and representatives appointed for the EGM (including any adjournment thereof) and the preparation and compilation of the attendance lists, minutes and other documents relating to the EGM (including any adjournment thereof), and in order for the Company (or its agents) to comply with any applicable laws, listing rules, regulations and/or guidelines (collectively, the "**Purposes**"), (ii) warrants that where the member discloses the personal data of the member's proxy(ies) and/or representative(s) to the Company (or its agents), the member has obtained the prior consent of such proxy(ies) and/or representative(s) for the collection, use and disclosure by the Company (or its agents) of the personal data of such proxy(ies) and/or representative(s) for the Purposes, and (iii) agrees that the member will indemnify the Company in respect of any penalties, liabilities, claims, demands, losses and damages as a result of the member's breach of warranty.

FORM OF PROXY

CDS Account No.

Hibiscus Petroleum Berhad
Registration Number: 200701040290 (798322-P)

*I/We____

I.C. No. / Passport No. / Registration No. / Company No. ______________________________

of ____

being a member of **HIBISCUS PETROLEUM BERHAD** (“**HIBISCUS PETROLEUM**” or “**Company**”)

hereby appoint ____

I.C. No. / Passport No. ____

of ____

or failing him/her ___________________________, I.C. No. / Passport No.________________________

of ____

or failing him/her, the CHAIR OF THE MEETING as my/our proxy, to vote for me/us on my/our behalf at the Extraordinary General Meeting (“**EGM**”) of the Company to be held via a virtual platform at the broadcast venue at Tricor Business Centre, Gemilang Room, Unit 29-01, Level 29, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur, Malaysia (“**Broadcast Venue**”) on Tuesday, 28 December 2021 at 9.30 a.m. or at any adjournment thereof, on the following resolution (with or without modifications) referred to in the Notice of the EGM by indicating an “**X**” in the space provided below:

RESOLUTION	**FOR**	**AGAINST**
Ordinary Resolution - Proposed Acquisition		

Dated this ______ day of ______________ 2021

Signature / Common Seal	
No. of Shares held	

For appointment of two (2) proxies, percentage of shareholdings to be represented by the proxies			
	No. of Shares	**Percentage**	
Proxy 1			%
Proxy 2			%
Total		**100**	**%**

Notes:

1. *In light of the Coronavirus ("**COVID-19**") pandemic and in line with the Guidance and Frequently Asked Questions ("**FAQs**") on the Conduct of General Meetings for Listed Issuers issued by the Securities Commission Malaysia, the EGM of the Company will be conducted entirely on a virtual basis through live streaming and online remote voting via Remote Participation and Voting ("**RPV**") facilities. The Company has appointed Tricor Investor & Issuing House Services Sdn Bhd ("**TIIH**") as the Poll Administrator for this EGM to facilitate the RPV via TIIH Online website at https://tiih.online. The procedures for members to register, participate and vote remotely via the RPV facilities are provided in the Administrative Guide for this EGM.*

2. *The Broadcast Venue is strictly for the purpose of complying with Section 327(2) of the Companies Act, 2016, which requires the Chair of the meeting to be present at the main venue. Members/proxies **are NOT** to be physically present at the Broadcast Venue on the day of this EGM.*

3. *For purposes of determining who shall be entitled to attend this EGM in accordance with Clauses 72(b) and 72(c) of the Company's Constitution and Section 34(1) of the Securities Industry (Central Depositories) Act, 1991, the Company shall be requesting Bursa Malaysia Depository Sdn Bhd to issue a General Meeting Record of Depositors as at 21 December 2021 and only Depositors whose name appear on such Record of Depositors shall be entitled to attend, speak (in the form of real time submission of typed texts) and vote via RPV at this EGM.*

4. *A member shall be entitled to appoint up to two (2) proxies to attend and vote at the EGM via RPV. Where a member appoints more than one (1) proxy, the appointments shall be invalid unless he specifies the proportions of his holdings to be represented by each proxy. A proxy appointed to attend and vote at the EGM via RPV shall have the same right as a member to speak (in the form of real time submission of typed texts) at the EGM.*

5. *A proxy or attorney or a duly authorised representative may, but need not be a member of the Company. There shall be no restriction as to the qualification of the proxy.*

6. *Where a member is an authorised nominee as defined under the Securities Industry (Central Depositories) Act, 1991 which is exempted from compliance with the provisions of subsection 25A(1) of the Securities Industry (Central Depositories) Act, 1991 (Exempt Authorised Nominee) which holds Ordinary Shares in the Company for multiple beneficial owners in one (1) securities account (Omnibus Account), there is no limit to the number of proxies which the Exempt Authorised Nominee may appoint in respect of each Omnibus Account it holds. Where the Exempt Authorised Nominee appoints more than one (1) proxy, the proportion of shareholdings to be represented by each proxy must be specified in the instrument appointing the proxies.*

7. *A member who has appointed a proxy or attorney or authorised representative to attend and vote at this EGM via RPV must request his/her proxy to register himself/herself for RPV at TIIH Online website at https://tiih.online.*

   Please follow the procedures for RPV set out in the Administrative Guide.

8. *For members who wish to appoint a proxy, the appointment of a proxy may be made in hard copy form or by electronic means.*

Proxy Forms must be submitted in the following manner, not less than forty-eight (48) hours before the time appointed for holding the EGM or adjourned meeting provided that in the event the member(s) duly executes the Form of Proxy but does not name any proxy, such member(s) shall be deemed to have appointed the Chair of the meeting as his/their proxy, provided always that the rest of the Form of Proxy, other than the particulars of the proxy has been duly completed by the member(s):

(i) In hard copy form

(a) To be valid, the Form of Proxy duly completed must be deposited at the Company's Share Registrar, Tricor Investor & Issuing House Services Sdn Bhd's address at Unit 32-01, Level 32, Tower A, Vertical Business Suite, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur or its Customer Service Centre at Unit G-3, Ground Floor, Vertical Podium, Avenue 3, Bangsar South, No. 8, Jalan Kerinchi, 59200 Kuala Lumpur.

(b) If the Form of Proxy is signed under the hands of an appointor or his attorney duly authorised (or if the appointor is a corporation, the Form of Proxy must be executed under its common seal or under the hands of an officer or attorney duly authorised), it should be accompanied by a statement reading "signed as authorised officer under Authorisation Document which is still in force, no notice of revocation having been received". If the Form of Proxy is signed under the attorney duly appointed under a power of attorney, it should be accompanied by a statement reading "signed under Power of Attorney which is still in force, no notice of revocation having been received". A copy of the Authorisation Document or the Power of Attorney, which should be valid in accordance with the laws of the jurisdiction in which it was created and is exercised, should be enclosed in the Form of Proxy.

(ii) Via Tricor Online System (TIIH Online)

The Proxy Form can be electronically submitted via TIIH Online at https://tiih.online. Please follow the procedures set out in the Administrative Guide.

9. Pursuant to Paragraph 8.29A of the Main Market Listing Requirements of Bursa Malaysia Securities Berhad, the resolution set out in the Notice of this EGM will be put to vote by way of poll. An Independent Scrutineer will be appointed to verify the poll results.

PERSONAL DATA POLICY

By submitting an instrument appointing a proxy(ies) and/or representative(s), the member accepts and agrees to the personal data privacy terms set out in the Notice of EGM dated 13 December 2021.

Fold this flap for sealing

Then fold here

AFFIX
STAMP

Share Registrar

TRICOR INVESTOR & ISSUING HOUSE SERVICES SDN BHD
Unit 32-01, Level 32, Tower A
Vertical Business Suite, Avenue 3
Bangsar South
No. 8, Jalan Kerinchi
59200 Kuala Lumpur
Malaysia

1st fold here